Department for
Energy Security
& Net Zero

Local Electricity Markets

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Executive Summary

CEPA has been engaged by the Department for Energy Security & Net Zero to identify and assess 'local energy market models' that could potentially be introduced in Great Britain (GB). This report sets out our findings on the potential design and implementation of local market models in the GB context, and the associated benefits and risks.

Project context

A 'local market' refers to market arrangements that place greater emphasis on balancing electricity supply and demand at the distribution network level. This contrasts to current market arrangements, whereby electricity market and system operation is focussed on transmission-connected participants and the distribution network is not explicitly reflected in the clearing of wholesale, balancing and ancillary services markets. As substantial quantities of distributed energy resources (DER) connect to the system, active management of distribution constraints becomes more important. How the market operator does this, and the impact on price signals, are at the heart of local market design.

In GB, a more active approach to distribution network management is already being developed incrementally, for example through 'flexibility markets'. The models described in this report differ in that they aim to integrate transmission- and distribution-level resources within a common national market framework.

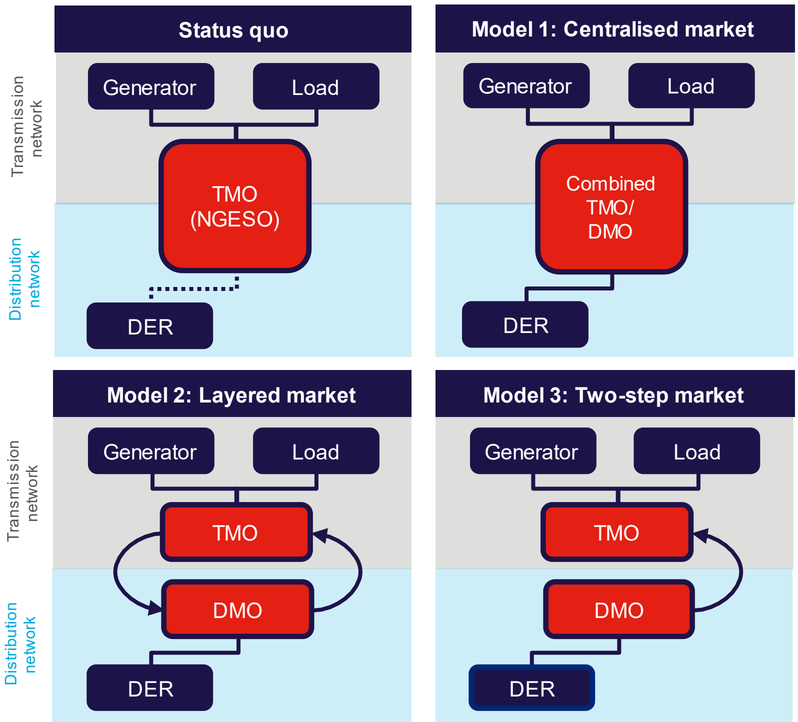
Summary of the local market models

Our research identified three overarching local market structures (Figure 1):

- Model 1 – Centralised market. This model represents both transmission and distribution level resources/networks in a central market clearing process, run by a single market operator (MO). The key difference from current market arrangements is the explicit inclusion of distribution constraints in the clearing algorithm.
- Model 2 – Layered market. This model seeks to address the computational and information challenges of Model 1 by dividing responsibility for balancing supply and demand between separate distribution and transmission level markets and market operators. Bi-directional communication between the market layers iterates towards a coordinated system-wide clearing solution. Conceptually, the DMO is acting like a flexible generator or load connected to the transmission network.
- Model 3 – Two-step market. This model also reflects separate distribution and transmission level markets/operators. Market clearing is sequential, starting with the distribution layer. Unlike Model 2, communication is in one direction, with the distribution market clearing solution providing a fixed input to the transmission level market.

Conceptually, in this model the DMO is more akin to an inflexible transmission-connected generator or load.

Figure 1: Local market model structure, compared to status quo



Source: CEPA. TMO = transmission market operator, DMO = distribution market operator

At this point in time, the local market models discussed in this report remain relatively novel concepts. We have not identified examples of these models in operation, nor detailed design descriptions in the available literature. Questions remain around their practical feasibility. Nonetheless, several observations on relative advantages and disadvantages can be made, summarised in Table 1 below (see section 3 for further details). Further detailed design development and testing how the models would perform in ‘real life’ use cases would assist to validate these comparisons and identify a potential preferred model for GB.

Table 1: Key advantages and disadvantages of the models

Model	Advantages	Disadvantages
Status quo	• Current arrangements are well-established and understood. • Distribution network operators (DNOs) and the electricity system operator (ESO) are continuing to explore how DER can be better integrated within the existing high-level market framework. May go some way to achieving the theoretical benefits of a local market model through a more incremental approach.	• Does not co-optimise transmission- and distribution-level resources, resulting in an inefficient market clearing solution. • Barriers to DER integration and market participation may still persist after existing plans are implemented, which may hinder optimal investment in these resources. • Current approach (and planned developments) could be described as somewhat piecemeal, with many local variations. May be less efficient / harder for DER to engage with than single national approach.

Model	Advantages	Disadvantages
Model 1 – Centralised market	• In principle, can optimally utilise resources (assuming MO has accurate information). • Resources at transmission and distribution levels compete on equal footing. • Economies of scale/scope from combined DMO/TMO. • Compared to status quo and Model 3, may create a larger pool of resources to meet system needs, with benefits for liquidity and competition.	• A single, integrated market clearing process presents computational challenges. • Different physical characteristics of high and low voltage networks means it may not be possible to simply ‘extend’ existing market clearing algorithms. Alternatives are unproven. • Challenging for a single MO to monitor, administer, verify and maintain required information.

Model	Advantages	Disadvantages
Model 2 – Layered market	• In principle optimal use of resources, per Model 1. • May enable DMO processes tailored to local conditions and/or support great innovation. • Breaking market clearing into smaller chunks may address practical challenges of Model 1. • Compared to Model 1, can enable economies of scope/scale from combined distribution system and market operator roles. • May ameliorate some data privacy concerns.	• Ability to deliver an optimal / feasible market clearing relies on iterative process converging with sufficient speed and accuracy. • Multiple entities would need to develop and maintain market operator capabilities (e.g., systems and processes) which may be more costly.
Model 3 – Two-step market	• A two-step market clearing process, with one-way flow of information, may avoid the computational challenges of Model 1 and concerns regarding the feasibility of an iterated solution in Model 2. • As for Model 2, separate DMO / TMO roles may address information challenge of Model 1. • Per Model 2, may ameliorate some data privacy concerns.	• Two-step process does not co-optimise transmission and distribution level resources, resulting in inefficient market clearing solution. • May maximise use of DER, encouraging uptake. However, it is unclear if this would result in lower system costs and emissions. • Less competition between transmission and distribution level resources.

Summary of key findings

DESNZ posed several questions to be addressed through this engagement. Our findings are summarised below, with signposts to the relevant sections of the main report.

How would local markets function for different market participants? How would local markets be governed and co-ordinated both at the local and national level?

In principle, the three local market approaches that we have identified could potentially apply to the balancing mechanism, the wholesale market, and/or the procurement of certain ancillary services. Different challenges and considerations are relevant to each context.

- The balancing mechanism already takes account of transmission network constraints. While representing distribution level constraints in this process adds considerable complexity, it could also be seen as an extension of the current approach. The application of the three models in balancing timeframes is discussed in sections 3.3 to 3.5.
- The wholesale market currently consists of bilateral contracts (that may be struck years in advance of when the electricity is delivered) and trades through the centralised day-ahead and intra-day market exchanges.
    - The introduction of a local markets model would not change the decentralised bilateral trading arrangements, although it is possible that particular local market design choices could impact contracting strategies.
    - In contrast, including transmission and distribution network constraints in the day-ahead and intra-day market clearing processes would be a substantial change to existing arrangements. This is because the exchanges do not currently reflect network constraints. Incorporating constraints into these markets – a key feature of a local market model – may mean that they could no longer be operated by exchanges (see section 3.7).
- The adoption of a local markets approach for ancillary services largely depends on the characteristics of the services the GB system requires and the degree of service standardisation that is possible across the transmission and distribution network levels. These issues are discussed in section 3.8.

Further details on how each model could function are set out in section 3.

How would investment, locational, and operational price signals be sent at the local and national level?

Investment and operational decisions are influenced by both market quantities (which resources are cleared and at what volume) and prices (the price at which cleared quantities are settled). Efficient signals are created by ensuring that market quantities and prices – whether wholesale, balancing, or ancillary services – accurately reflect network conditions and the least cost mix of resources to meet supply and demand. Local markets seek to achieve this by more accurately reflecting distribution networks and the resources connected to them in market clearing. Sections 3.3 to 3.5 illustrate how the local market models contribute to efficient market clearing, compared to current arrangements (section 3.2).

For each local market model (and indeed the status quo) a variety of price formation options could be adopted (see section 3.6.6). These options differ in how accurately they reflect the locational and temporal value of energy. The chosen pricing approach will impact the extent to which the theoretical efficiency benefits of local markets are realised. As seen in debates regarding the possible introduction of nodal pricing at the transmission network level, different pricing approaches may have implications for existing business models and contracting arrangements, which require careful consideration.

What wider market arrangements (if any) might facilitate the adoption of local markets? What barriers or implementation challenges might need to be overcome? What are the key enablers needed for implementation (e.g., market facilitators, community or innovation projects, data and digitalisation tools)? What other infrastructure or system changes would be necessary?

As noted in section 1.4, efficient integration of DER may be impacted by a range of broader policy settings. For example, Transmission and Distribution Network Use of Services (TNUoS and DNUoS) charges could either complement or blunt the signals provided by a local market.

In addition, we have identified some implementation considerations for local markets. These reflect:

- The mathematical and computational challenges relating to distribution network constraint formulation and market clearing algorithm design,
- The sheer volume of information relating to network conditions and constraints that would need to be collected and maintained, and
- The challenge of actually measuring and monitoring this information, which is not widespread in distribution networks today.

In section 5.1, we consider how current distribution system operator (DSO) transition plans are moving towards the realisation of these capabilities.

What would be a realistic timescale for implementation?

Through the Review of Electricity Market Arrangements (REMA), DESNZ is seeking to put in place market arrangements that will facilitate decarbonisation of the electricity sector by 2035. Our findings (section 5.3) suggest that it could be challenging to successfully design and implement a local market model within timeframes that would materially support this goal.

Is the local markets option compatible with nodal/zonal pricing, and with a green power pool?

Our conclusion is that the local market models are compatible with either nodal or zonal pricing.

However, we have identified that a local markets approach and a split market/green power pool might not always be compatible:

- DER could participate in the 'as available' or 'on demand' wholesale markets depending on whether their supply or demand are firm and pay or be paid accordingly. Real-time balancing would then occur in conceptually the same way as described in the local market models, with the balancing mechanism process taking account of both transmission and distribution level constraints.
- However, there would appear to be a conflict if local market/split market approaches are applied together at the wholesale market level. As described in section 3.7, applying a 'local markets approach' to the wholesale market would involve the market being cleared with transmission and distribution constraints being taken into account (i.e., a security constrained economic dispatch). This type of approach inherently requires a whole of system optimisation – which would not appear to be compatible with a split market approach.

These conclusions are based on a high-level description of how these reforms – and indeed reforms to introduce a local markets approach – could operate. It is possible that this conclusion could change over time as more design detail is developed. Our findings are discussed in more detail in section 5.2.

What international examples (if any) exist with regard to dynamic and real-time system balancing and the procurement of balancing services at a distribution/local level?

We have not identified examples that have been implemented at a system-wide level, which is consistent with the findings of other recent reviews.[1] While numerous innovation trials are ongoing in GB and elsewhere, with interesting results, these are based on simplifications that would not be possible in a 'real life' application. As a result, it is fair to say that the local market models we have identified are all unproven in practice and that a lengthy detailed design process would be required to develop the models to the point of implementation. This may change as experience from trials and evidence from the academic literature deepens over time.

Has the option been considered elsewhere but ultimately discounted? If so, why?

Local markets have been, and continue to be, investigated in a range of jurisdictions including the European Union (EU), the United States (US) and Australia. We are not aware of any jurisdictions definitively ruling out local markets. At the same time, we have not identified decisions to press ahead with implementing such models. Rather, it appears that the concept is being explored and developed incrementally. This may reflect that successful implementation of a local market model relies on DSO capabilities that are still being developed.

Such capabilities may be needed to safely and securely operate the power system, even without a local market framework to provide price signals. Development is taking place through

[1] For example, see Edmunds, C., (2022), p. 32.

innovation trials, as well as through industry-led processes that aim to improve active distribution network management. For example, this includes:

- The Energy Network Association's (ENA) Open Networks programme in Great Britain. Distribution networks are also receiving funding to develop their capabilities through the RIIO-ED2 revenue determinations.
- The Open Energy Networks collaboration between in the Australian Energy Market Operator (AEMO) and Energy Networks Australia.
- The CoordiNet project in the EU.

How might participation in local markets be incentivised/made attractive?

The local market models we have identified are focused on achieving efficient market clearing and providing price signals that accurately reflect the locational and temporal value of energy. These outcomes do not guarantee participation will in fact be attractive to many DERs. This will – appropriately – depend on whether the value these resources can deliver via the local market exceeds their opportunity cost of providing the service.

To facilitate participation, the local market design should as far as possible reduce barriers to entry – for example, by ensuring that participation requirements are not unnecessarily restrictive.

DSO capabilities – such as better visibility of distribution networks and forecasting of DER – are important enablers of local markets. Development of these capabilities will also improve opportunities for DER to participate in existing markets, in the absence of a local markets approach being implemented. For example, replacing static – and potentially conservative – DER export limits with more accurate representations of distribution constraints in market clearing may allow more system needs to be met by DER. This would improve the business case for investing in distributed resources by enabling DER to compete with transmission-connected resources in existing markets on a more equal footing. As described in section 5.1, DNOs have existing plans to further develop DSO capabilities during the RIIO-ED2 price control period. The electricity system operator (ESO) is also planning improvements to the integration of DER in the markets that it operates. While the implementation of a local market model would require additional actions and investments, these existing initiatives can be expected to improve DER integration relative to today.

How might the model address (or not address) the current challenges in the wholesale electricity market? How might local markets affect system costs, innovation, competition, and the business case for low carbon flexible technologies?

We suggest that the primary potential benefits of local markets relate to:

- Enabling the most efficient system-wide market clearing solution, across both transmission and distribution level resources. This may deliver incremental gains in the utilisation of both transmission and distribution level resources, with potential benefits in relation to reducing system costs. However, different models may be more (Model 1 and 2) or less (Model 3) successful at achieving this outcome.

- Providing a consistent definition of responsibilities for dispatch of transmission / distribution network resources through the design of the local market model itself, improving coordination between the network levels.
- Potentially, depending on the pricing approach adopted, the provision of sharper locational price signals to distribution-connected resources relative to current arrangements. As discussed in section 3.6.6, this outcome only arises with certain pricing models.

We elaborate on these benefits in section 4.1. We discuss implications for competition in section 4.3.1 and impacts on low carbon business cases in section 4.1.3.

How do benefits and risks change within voluntary vs mandatory local markets?

A greater level of participation from flexible resources would enhance the benefits associated with a local market model.

In the current market arrangements, participation obligations vary across the wholesale, ancillary service and balancing markets. The strictest obligations relate to the balancing mechanism, where large generators are required to submit balancing bids and offers. If a local market approach is considered for the balancing mechanism, it may be appropriate to review which type of participants should face similar obligations to large generators in the transmission-level market today. Considerations would likely include the flexibility that different resources can offer and the costs associated with participating. This would be important to avoid imposing unreasonable burdens on participants, which might create opposition to the introduction of such a market. We discuss these issues in section 3.6.5.

An alternative approach may be to seek to encourage participation through reducing barriers to entry.

How might local markets overcome the low liquidity seen in current local flexibility markets?

DNO flexibility markets have in some cases seen relatively low levels of participation and the quantities of flexibility services that DNOs have targeted have not been fully met. However, local markets that coordinate resources at the distribution and transmission level may be less likely to suffer from liquidity issues than standalone DNO flexibility markets that seek to address a specific distribution system constraint, because they are broader in scope. Further, the likelihood of insufficient offers to meet system requirements is far less likely, as all flexible resources at the transmission and distribution networks are available to ensure that supply and demand balance at the national level. However, any costs and complexities associated with DER participating in local markets can also discourage entry and limit liquidity. Participation requirements would therefore require careful consideration in the design of a local market. We elaborate on these points in sections 3.6.4 and 4.3.1.

Summary of our recommendations

Overall, we consider that a local markets approach is consistent with the REMA consultation paper's focus on improved locational signals and distribution network visibility. However, there are questions around the materiality of the potential benefits, the scale of the investment needed, and the timeframes in which the benefits might be achieved.

This may point to a relatively incremental approach to further policy development in relation to local markets. We suggest that appropriate next steps are to:

- Develop the design of a local market model (or models) in greater technical detail.
- More precisely define and/or quantify the benefits associated with particular local market models (relative to the status quo and each other).
- Assess whether other REMA market design directions, and Ofgem's[2] imminent conclusions in relation to sector governance, point to a particular local market model (or models) being most suitable for GB.
- Maintain a watching brief on the progress against DSO / ESO transition plans in GB, as well as innovation trials that are taking place in other jurisdictions. Outcomes from these processes may provide further evidence on the feasibility of particular local market approaches.

Informed by the steps outlined above, in the near- to medium-term it may be appropriate for DESNZ to provide stakeholders with an indication of the likely long-term direction of travel in relation to local markets. While it may be premature at this point to definitively decide on any particular model, a high-level direction may provide a common point of reference to guide industry efforts and expectations. This may help to address a potential risk that an incremental approach to local markets could result in increasingly divergent approaches across the DNOs as they develop their own approaches to managing distribution network constraints. While local variation may be appropriate up to a point, it would likely make the implementation of a nationally consistent approach harder over time, particularly as DER business models adapt to specific arrangements.

Structure of this report

The remainder of this report is structured as follows:

- Section 1 (Introduction) provides the context for this report and sets out key definitions.
- Section 2 (Why introduce local markets?) describes the existing electricity market arrangements and explores how the concept of local markets differs.
- Section 3 (Local market models) introduces the three local market models that we have identified through a targeted literature review. Each model is presented in simple terms,

[2] The Office of Gas and Electricity Markets, supporting the Gas and Electricity Markets Authority, is the government regulator for the electricity and downstream natural gas markets in Great Britain

with a stylised worked example used to illustrate key differences to the current market arrangements. This section also discusses a range of design elements that would need to be defined in order to implement the local market models.

- Section 4 (Assessment of the models) presents a high-level analysis of the benefits and risks associated with a local markets approach.
- Section 5 (Implementation pathways) discusses practical implementation considerations and recommended next steps to move policy thinking on this topic forward.
- Appendix A describes the methodology for the targeted literature review.
- Appendix B provides the references we have relied on to develop this report.

1 Introduction

CEPA has been engaged by the Department for Energy Security & Net Zero (DESNZ) to identify and assess 'local energy market models' that could potentially be introduced in Great Britain (GB).

1.1 Context

This project will inform DESNZ' internal consideration of whether a local market model should be pursued further under the Review of Electricity Market Arrangements (REMA). Local markets are being considered through REMA as a means of incentivising efficient investment in and use of distributed energy resources (DER) through market price signals.

This report sets out our findings on the potential design and implementation of local market models in the GB context, and the associated benefits and risks.

1.2 Our approach

For this project, we have adopted a qualitative, desk-based approach to identify, define and assess different design options for local markets in the GB context. More specifically, we have:

- Undertaken a targeted review of academic literature and studies from industry / government agencies to identify the range of local market models that could be considered for GB.
- Identified the main design elements necessary to implement the models, noting where there is optionality.
- Developed stylised worked examples to illustrate how outcomes could potentially differ under a local market model, relative to the status quo.
- Undertaken a limited assessment of the risks and benefits associated with each model, with a focus on how a local markets approach could address the objectives of REMA.
- Considered possible implementation pathways in the event that a local market model was introduced in GB.

It is important to highlight that while the technical capabilities needed to implement a local market are developing rapidly, to our knowledge none of the models described in this report have been introduced at a system-wide level. Consequently, it is fair to say that the local market models we have identified are all unproven in practice and therefore somewhat futuristic. Accordingly, a thorough design process would be needed to develop the models up to stage where feasibility, costs and benefits could be comprehensively assessed. We provide suggestions on a possible path forward in section 5.

1.3 Definitions

Throughout the literature, consistent terminology is not applied in discussions of local markets and associated concepts. This section introduces and defines the key terms we use to describe electricity market participants and functions, to facilitate a consistent description of the alternative market models.

The terminology outlined in this section also allows us to describe different market models in terms of roles, without expressing views as to which entities – new or existing – should undertake these roles. Therefore, in this report, terms like ‘system operator’ and ‘market operator’ are used to refer to functions rather than specific governance arrangements. Governance arrangements are being examined as part of other ongoing processes[3] and are outside the scope of this report. References to institutions in the current GB market are included in this section only for illustrative purposes, to facilitate understanding of the different roles.

We use the term Transmission Network Operator (TNO) to refer to the role of building and maintaining the assets that form the high-voltage electricity transmission network in a way that enables the safe, secure, and reliable transfer of electricity between parties connected to the transmission grid (large electricity generators and industrial customers, and distribution networks). In GB, there are three TNOs: National Grid Electricity Transmission (NGET), SSEN Transmission and SP Transmission.

We use the term Transmission System Operator (TSO) to refer to the role of monitoring and managing the transmission system, including real-time system operation, in accordance with system constraints and regulated standards. System constraints are the parameters within which the electricity transmission network can be operated without exceeding its physical limits. For example, in simple terms, only a certain amount of electricity may be carried in a certain part of a network, before the frequency, voltage, or temperature on certain network assets exceeds safe levels. In GB, the TSO is National Grid Electricity System Operator (NGESO).[4]

We use the term Transmission Market Operator (TMO) to refer to the role of operating markets for energy and other services exchanged between parties connected to the transmission network. This could include wholesale, balancing and ancillary services markets. This role entails receiving bids and offers from market participants to provide or consume electricity. The TMO then clears the market – i.e., identifies the optimal combination of available bids and offers to match demand with supply. The TMO role may also include financial settlement of the market. In GB, the TMO role is split. In the wholesale market, formal day-ahead and intra-day markets are operated by two exchanges: NordPool and European Power Exchange SE (EPEX). NGESO is responsible for operating the balancing market and procuring ancillary

[3] For example, Ofgem’s ‘Future of local energy institutions and governance’ consultation.
[4] NGESO is a separate business to NGET, within the National Grid group.

services. Finally, Elexon is responsible for financial settlement and implementation of the Balancing and Settlement Code (BSC).

Traditionally, distribution networks were built to convey electricity from the high-voltage transmission network to consumers connected at the distribution level. However, this has changed in recent years, with the increasing volume of DER capable of injecting energy into the distribution network or varying their consumption of energy from the distribution network. In this report, we adopt a broad definition of DER, which encompasses electricity generation, storage and energy users who are able to flex their consumption. This definition reflects the fact that DER, similarly to parties connected to the transmission network, can provide services not only by injecting energy into the grid, but more broadly by increasing and decreasing their supply and demand in line with the needs of the system.

Uptake of DER has increased the complexity of the distribution system. This is leading to the development of new functions and capabilities to support more active planning and operation of the distribution network, and new markets for services provided at the distribution network level. In this report, the term Distribution Network Operator (DNO) refers to the role of building and maintaining the assets that form the distribution network. The term Distribution System Operator (DSO) refers to the monitoring and operation of the distribution system (including in real time) in accordance with physical network constraints, technical requirements, and regulated standards. The term Distribution Market Operator (DMO) refers to the role of operating markets for energy and other services exchanged between parties connected to the distribution network. In GB, there are six DNOs, who are in the process of developing DSO capabilities (see section 2.4.4). At present, aside from limited trials there are no DMOs in GB – or indeed in other electricity markets that we are aware of.

Participation of DER in transmission or distribution level markets could be direct or, alternatively, another party could act on their behalf – for example, submitting bids and offers, or remotely controlling equipment to comply with instructions from the TMO and/or DMO. In this report, we use the term aggregator to refer to a party who participates in the market on behalf of DER. An aggregator could be the DER's supplier, or an independent third-party. In this report, we assume that aggregators do not take network constraints or the location of DER into account: rather this role sits with the TMO and/or DMO.[5]

1.4 Related topics

There are a variety of topics that are adjacent to the concept of local markets, but which are not in the scope of this project. These topics influence the efficiency of DER integration, alongside local markets. We briefly note them, and their relationship to local markets, here:

- Efficient distribution network planning is a function of the expected real-time production and consumption of electricity across the network. Local markets are intended to:

[5] Aggregators may be responsible for providing the DMO with information on the location of DER resources on whose behalf they are bidding.

  - Reduce capital expenditure of distribution networks by instead (where efficient) allowing some constraints to bind in real time and be managed through the local market; and
  - Improve the incentives on DER to invest and operate efficiently, in turn changing the business case of distribution investments.
- In turn, this may impact the appropriate network access standard that DER receives. This question relates to whether DER should receive firm or interruptible connections, what volume of imports/exports to the grid is provided, and how this impacts connection charges. A related issue is whether there are consistent access arrangements across transmission- and distribution-connected resources.
- Distribution (and transmission) network charging is how DNO (and TNO) costs are recovered from network users, including DER. Tariff design can influence investment and operational decisions, including bid/offer prices in the local market, and ultimately affect the efficiency of outcomes.
- Similarly, feed-in tariffs, contracts for difference and other incentive schemes for renewable generation uptake at the distribution level could also impact both investment and operational decisions.
- General transmission-level market design issues which, if inconsistent with local markets at a distribution level, may induce inefficient biases in operational or investment timeframes (either for or against distribution- or transmission-connected resources).
- Finally, Ofgem has commenced a review into the effectiveness of institutional and governance arrangements for distribution networks in the context of the transition to net zero. Although the local market models we have identified could potentially be implemented under multiple institutional and governance arrangements, Ofgem’s decision may point to one of the local market models we have identified being more suitable for GB.

Policy decisions on these topics may impact the benefits that could be realised by local markets – either by blunting the operational and investment signals that local markets create, or through facilitating similar outcomes through alternative means. We return to this point in the discussion of benefits in section 4.

2 Why Introduce Local Markets?

In this section, we contextualise the local market models considered in this report. First, we outline our understanding of DESNZ' objectives for evaluating such markets as a potential REMA policy option. We then contrast the concept of local markets to current electricity market arrangements in GB.

2.1 Context

The term 'local market' broadly refers to market arrangements that place greater emphasis on the balancing of electricity supply and demand at the distribution network level. This contrasts to the current market arrangements, whereby electricity market and system operation is focussed on transmission networks and transmission-connected participants, with DER playing a relatively passive role.

We understand that DESNZ is investigating local markets as a means of facilitating efficient investment in and use of DER, by exposing these resources to market price signals that indicate the value of flexibility at different times and in different locations. Given growing volumes of DER, effective integration into electricity markets could help to address several challenges that DESNZ has identified with the current market design, as illustrated in Figure 2.

Figure 2: Challenges that local markets could help to address

2.2 Features of efficient markets

Locational value, temporal value, and visibility are all key to whether electricity markets efficiently clear and price the services that can be provided by DER. These concepts are expanded on below.

Locational value

Network constraints are a fundamental concept in efficient energy pricing.

Without constraints, the market operator has the simple decision of balancing supply and demand by clearing resources "in merit order" regardless of their location. That is, taking the generator or load that has made the lowest bid/offer, then the next cheapest, and so on, until the system is in balance. If there are no constraints, there is no need for a 'local market'.

However, when a piece of network equipment is at its limits (because, for example, the flow of electricity across the equipment cannot be safely increased), the market operator must adjust load and/or generation, relative to the unconstrained scenario when the cheapest bids/offers can simply be taken in merit order. Different generators and loads exacerbate or alleviate different network constraints by different amounts, with location being a key determining factor of the most appropriate resource to adjust. Therefore, to balance supply and demand efficiently, the market operator must take account of not only the bid/offer prices of the generators/loads, but also their locations on the network.

Historically, congestion on distribution networks has been low: networks have been built out to accommodate reasonable physical requirements, or DNOs have entered into contracts with network users to adjust their supply/demand to relieve congestion. With substantial quantities of DER and advances in metering, communications and IT, this may no longer be the most efficient approach. Rather, it may be more efficient to allow some constraints to bind and manage congestion by adjusting distribution-level consumption or generation through a market. How the market operator does this, and the prices that market participants get paid to make adjustments, is at the heart of the local market concept.[6]

As electricity flows across the network, some of the energy is lost as heat. The amount lost is a function of the distance the electricity travels, and so losses are also location-specific and impact locational value.

Temporal value

Another defining feature of electricity systems is that electricity is the ultimate perishable good: it cannot be stored.[7] If production of energy is instantaneously greater than its consumption, the frequency of the system increases. Conversely, a deficit in instantaneous energy production reduces system frequency. To securely and safely operate equipment, the frequency of the system must be kept in a narrow band.

Consequently, energy markets are highly time sensitive with both the balancing mechanism and ancillary services – such as frequency response and inertia response – used to manage the system in real time.

As in any commodity market, varying prices over time create risks for market participants. The prospect of prices changing every thirty minutes exaggerates these risks further. Risk averse market participants will hedge these risks by entering into contracts ahead of real time at pre-agreed prices. Current GB arrangements for these real-time balancing and ancillary services markets are outlined in section 2.4.

[6] As described in section 2.4.4, the concept of managing constraints rather than choosing to build out the electricity network is already being explored by the DNOs through local ‘flexibility markets’. These nascent markets seek to contract with local electricity sources or assets to modify their consumption or production of electricity to address distribution system constraints, which can be less costly than investing to augment the network.

[7] Even ‘storage’ like chemical batteries or pumped hydro-electric plants are not storing electricity *per se.* They are consuming electricity and producing chemical or gravitational potential energy, and then subsequently generating electricity using that chemical or gravitational potential energy.

Visibility

To operate an increasingly complex system efficiently, safely, and reliably, the market operator (via the DSO) will need visibility of conditions in the distribution system, including at lower voltage levels.[8] Visibility of the distribution network and distribution-connected resources also supports efficient market outcomes: if the market operator cannot accurately ‘see’ the distribution network, it cannot select the most optimal combination of resources to balance supply and demand.[9]

This presents a challenge in a distribution network context, as current levels of visibility are limited. Therefore, providing this information to the market operator implies a material increase in data measurement and monitoring on the distribution networks relative to today.

2.3 Why introduce local markets?

With widespread DER uptake, active and accurate coordination of these resources is increasingly important for enabling the transition to net zero at the lowest cost to consumers. However, as described in section 2.4 below, integration of these resources in the existing set of electricity market arrangements is relatively limited. Although DER, including small installations, are gradually gaining access to the wholesale, balancing and ancillary services markets, clearing of these markets does not consider constraints on the distribution system. While DNOs are developing markets to purchase services from DER, these are at an early stage, do not yet enable real-time procurement of services, and are not integrated with transmission level markets.

Accordingly, it is possible that under the current market arrangements:

- Supply and demand may not be balanced in the most efficient way, because the capabilities of all available resources and networks are not accurately reflected in the market clearing process.
- Market clearing results could potentially be incompatible with the physical limitations of the network, due to a lack of visibility of distribution resources and network conditions. This issue could also arise due to inadequate coordination between NGESO and DNOs.
- Price signals arising from the various markets may not accurately reflect the locational or temporal value of either distribution or transmission connected resources. This may contribute to inefficient operation of existing resources and sub-optimal siting decisions for new assets.

By more comprehensively reflecting distribution level constraints and resources in GB’s electricity markets, local markets could potentially assist to address these concerns. To illustrate where local markets might result improve outcomes, the following section outlines the

[8] This has been highlighted as a key enabler of DER integration in the policy literature. For example: CoordiNet (2020), Deliverable D2.2, considers the issue in detail. See also Energy Networks Association (2018), p. 77; and Energy Networks Australia (2020), p. 9.
[9] Energy Networks Association (2021), p. 23.

current GB market arrangements and highlights where the integration of distribution networks and DER is currently limited.

2.4 Current GB market arrangements

The current GB electricity market arrangements include:

- The wholesale market, which encompasses forward trading of contracts to buy and sell energy ahead of real-time balancing, enabling market participants to manage real-time price volatility.
- The balancing mechanism, in which the NGESO ensures that supply and demand are physically balanced (over 30-minute timeframes).
- Ancillary services markets, through which NGESO procures other services to ensure the power system is in balance over sub-30-minute timeframes, and for a variety of other physical requirements for the safe and secure operation of the system.
- Flexibility markets, which are emerging markets used by DNOs to procure services from DER ahead of real-time to assist in the active management of their networks.

These components of the current market arrangements are discussed below, highlighting the approach to integrating DER and distribution network constraints.

2.4.1 Wholesale market

In GB, the wholesale electricity market is the market where generators, suppliers, and non-physical traders enter into contracts to buy or sell electricity for delivery in future 30-minute intervals (settlement periods). Contracts can be struck years ahead and up to gate closure, which occurs one hour before the start of the settlement period. Contract positions must be notified to Elexon.

Contracts may be negotiated bilaterally or traded through power exchanges, which operate day-ahead markets (where parties trade energy for the next 24 hours) and intraday markets (where trading relates to the current day). In GB, day-ahead markets (auctions) are operated by NordPool and EPEX.[10] EPEX also operates intraday markets (auctions and continuous trading).[11]

[10] BEIS (2021), p.7.
[11] EPEX, https://www.epexspot.com/en/gb-market-post-brexit#gb-markets-and-trading-solutions-what-we-offer. Accessed November 2022.

DER and distribution networks in the wholesale energy market

Distribution networks:

The day-ahead and intraday markets clear on the basis of supply and demand for contracts, without considering the location of participants or network constraints within the GB system – either at the transmission or distribution level.

DER:

The participation of DER in the wholesale market depends on their size and licensable status.[12] Larger licensed embedded generators (i.e., generators connected to the distribution network) may participate directly in the wholesale market.[13] However, other DER assets must currently participate through their electricity supplier.[14]

2.4.2 Balancing mechanism

Participants must submit their final physical notification (FPN) – expected generation/demand for each settlement period – to NGESO at gate closure. Within any settlement period, generators are expected to generate and deliver, and suppliers are expected to use, their contracted volume of electricity. However, deviations from these contractual positions can arise in real time, for example if suppliers have forecast their demand incorrectly, generators are unable to produce the contracted amount, or problems arise with transporting electricity on the network. Therefore, the supply-demand imbalance must be managed in real time.

NGESO's primary real-time balancing tool is the balancing mechanism, where participants submit offers to increase generation or reduce demand and bids to reduce generation or increase demand relative to contracted amounts. NGESO determines the combination of balancing bids/offers and ancillary services (see section 2.4.3) that most efficiently match supply to demand whilst addressing any issues caused by transmission network constraints.[15]

Cleared balancing mechanism bids/offers receive their bid/offer price (i.e., a pay-as-bid approach). The costs of balancing the system are reflected in an energy imbalance price. Broadly, this reflects the volume weighted average cost of actions taken by NGESO to balance supply and demand. Imbalance costs are then recovered from market participants based on their imbalance position (the difference between metered volumes and contracted volumes, being either a surplus or a deficit).

As described below, the volumes that parties can offer to the balancing mechanism depend on the terms of their connection agreement with either NGESO or their DNO.

[12] Elexon, https://bscdocs.elexon.co.uk/guidance-notes/embedded-generation. Accessed November 2022.
[13] Ibid.
[14] Elexon has been considering a modification (P415) to the BSC that would allow smaller DER or DER aggregators to participate independently in the wholesale market as **virtual lead parties** (VLPs). Elexon (2022).
[15] Elexon, https://bscdocs.elexon.co.uk/guidance-notes/the-electricity-trading-arrangements-a-beginners-guide. Accessed November 2022.

DER and distribution networks in the balancing mechanism

Distribution networks:

The balancing mechanism only directly reflects transmission network constraints. Distribution network constraints may be indirectly reflected to the extent that the terms of connection agreements for distribution-connected resources limit what they can bid or offer (see details below).[16]

DER:

Following the P344 modification to the BSC, all controllable DER can participate in the balancing mechanism – either through their supplier, or through a VLP (which can be the DER itself, or a third-party aggregator).[17]

Participation of DER in the balancing mechanism is limited by the terms of their connection agreement. Additionally, other requirements for balancing mechanism participation include:[18]

1. Metering requirements. NGESO is continuing to define appropriate operational metering standards for DER (for both the balancing mechanism and ancillary services).
2. A minimum threshold of 1MW, which requires smaller DER to participate via an aggregator.

Connection agreements set out the access rights of energy resources connected to distribution networks, which defines their ability to inject or withdraw electricity from the power system. Arrangements currently differ depending on the size and other characteristics energy resources:

- Transmission-connected generators, and larger licensed embedded generators connected to the distribution network, have a defined transmission entry capacity (TEC) in their connection agreement with NGESO. TEC places a ceiling on the amount of energy a generator is able to export onto the transmission system, placing a cap on their combined FPN and balancing mechanism bids/offers. Access at the TEC is financially firm – that is the NGESO needs to compensate the generator (via the balancing mechanism) if exports are curtailed below its TEC.
    - Smaller embedded generators have connection agreements with the relevant DNOs. Ofgem's final decision on the Access Significant Code Review (SCR) has clarified arrangements for these parties.

[16] Ofgem (2018).
[17] Elexon (2018).
[18] NGESO (2022), *Operational visibility of DER*, May.

  - Generally small users have a standard connection, meaning that the DNO will ensure sufficient network capacity is available such that curtailment of these users is rare. [19]

- Larger users (both demand and generation) may have a standard or flexible connection. A flexible connection means that imports or exports can be restricted by the DNO if necessary to operate the system. Ofgem has determined that flexible connections must specify maximum curtailment limits and have an explicit end date, after which firm access must be provided.[20] If the DNO curtails load / output above the maximum limit, it must compensate the user. Compensation does not, however, apply to scenarios when users are curtailed due to transmission-level constraints.

2.4.3 Ancillary services

In addition to energy being traded in the wholesale market and balancing mechanism, NGESO procures ancillary services to support the secure operation of the power system.

In GB, there are a wide range of differently specified services, including frequency response, voltage control (e.g., through the provision of reactive power), inertia response, and black start (the procedure to recover from a total or partial shutdown of the electricity system).[21] Under the current market arrangements, ancillary services are procured and scheduled separately from energy (i.e., these services are not purchased and co-optimised in real time alongside the balancing mechanism).[22]

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[19] Ofgem defines small users as “households and non-domestic users that are billed on an aggregated and non-site-specific basis or who are metered directly using whole current meters”. Ofgem (2022), *Access SCR – Decision*, May, p.68. Larger users are those with an agreed import / export capacity, typically with current transformer (CT) meters).

[20] Exceptions apply, such as where the user has not requested a firm connection.

[21] NGESO, https://www.nationalgrideso.com/industry-information/balancing-services. Accessed November 2022.

[22] NGESO (2022), p.55

DER and distribution networks in ancillary services markets

Distribution networks:

When balancing the system in real time, NGESO directly considers transmission network requirements only.

DER:

NGESO has been increasing the scope for DER to provide ancillary services. For example, it recently introduced a Demand Flexibility Service that will run from November 2022 to March 2023, allowing flexible demand on the transmission and distribution networks to be remunerated for changing consumption in response to a signal from NGESO.[23] However, DER provision of ancillary services remains quite limited at present.

In some cases, connection agreements may impose rather strict limitations on DER participation in ancillary services markets. For example, active network management (ANM) schemes are becoming increasingly widespread in GB distribution networks and are also being deployed at the transmission network level. Broadly speaking, in ANM zones control systems continually monitor limits on the network, curtailing users with flexible connections if required to manage constraints.[24] We understand that assets in ANM zones may not be able to contract to provide ancillary services to NGESO, as the operation of the ANM scheme when there is a binding constraint could prevent the asset from providing the service.[25] For example, the ANM scheme might constraint generation in a given area which directly counteracts the desired effect of an ancillary service procured by NGESO.

2.4.4 Flexibility markets

In GB and elsewhere, DNOs have historically developed their systems to passively transfer energy from transmission networks to end users connected to the distribution network. Rapidly increasing volumes of DER have put pressure on this approach, given challenges associated with distribution network congestion and reverse power flows. In response, DNOs are moving towards more active network management by taking on some DSO functions.[26]

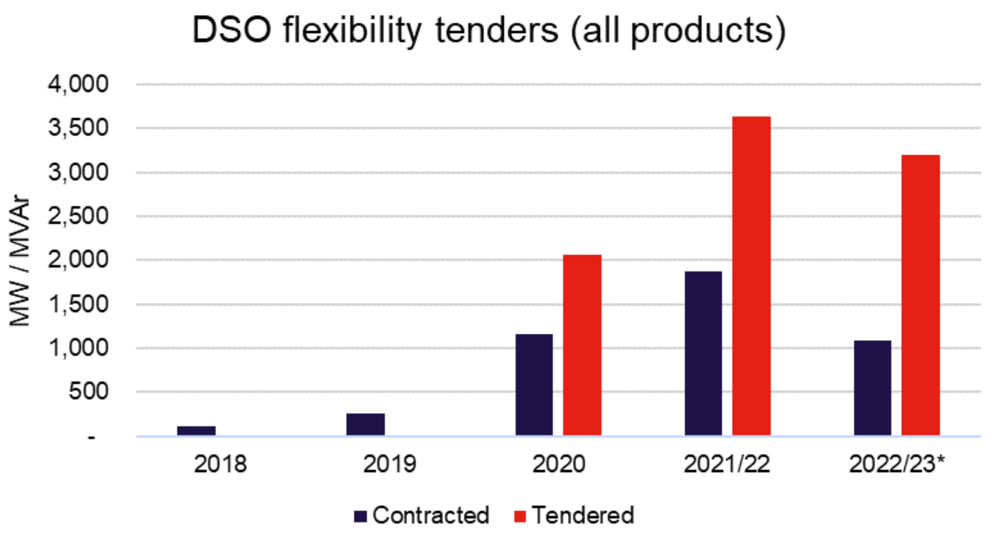
As part of a shift towards a ‘smart and flexible energy system’[27] DNOs have established local ‘flexibility markets’ across GB. These markets involve the DNOs purchasing services from DER

[23] NGESO, https://www.nationalgrideso.com/news/esos-demand-flexibility-service-launches. Accessed November 2022.
[24] See, for example, National Grid, https://www.nationalgrid.co.uk/our-network/active-network-management-anm. Accessed December 2022.
[25] Cornwall Insights (2021), Optimal Coordination of Active Network Management Schemes with Balancing Services Markets, May, p. 7.
[26] Ofgem (2022) is continuing to explore whether certain DSO functions should be delivered by the incumbent DNOs, or third parties.
[27] Ofgem and BEIS (2021).

to assist in the management of their networks – typically well in advance of real time. DNOs are increasing operational visibility of their networks and their understanding of system requirements.

We understand that although participation is growing, these markets are at a relatively early stage of development.28 For example, Figure 3 indicates that contracted volumes of flexibility have thus far been less than total capacity that the DNOs have targeted through their tenders. The Energy Networks Association has noted that bringing further liquidity to these markets – meaning the volume of resources than provide flexibility services – is a key focus area for 2023.

Figure 3: DSO - Volumes of tendered and contracted flexibility



Source: Energy Networks Association (2022b), 2022 Flexibility Consultation Wrapper Document, August, p.5. 2022/23 indicates volumes contracted / tendered to date.

Further, flexibility providers have noted limitations on the value they can access in DNO markets. For example, in UKPN's recent consultation to inform its flexibility markets, service providers commented that from their perspective: [29]

- The value of flexibility markets is low relative to the national balancing mechanism or wholesale markets - related to both the overall size of the markets, and the prices offered.
- There is currently a lack of long-term visibility and fragmentation across different flexibility procurement rounds.
- They face challenges in committing far ahead of real time, as this impedes their optimisation of revenues across flexibility market and wholesale market opportunities.
- Current reliance of relatively manual procurement processes (e.g., emails) create costs, complexity and a higher risk of error.

[28] Energy Networks Association (2022a), pp. 11-13.
[29] For example, see UKPN (2022), *Consultation: A step change in local flexibility*, October, pp.13-16.

- The range of flexibility products may not appeal to all potential providers.

Some of these issues may improve over time as DNOs continue to develop their markets. This may involve DNOs increasingly tailoring their approaches to flexibility providers within their footprint.

DER and distribution networks in flexibility markets

Distribution networks:

While Ofgem[30] has noted that DNOs in GB are now increasing their network visibility, the ENA has highlighted that limitations remain.[31] For example, available data on thermal ratings are not yet suitable for real-time operation, as they are based on seasonal average temperatures.[32] While dynamic ratings are under investigation, these are not widely available for forecasting or real-time operation.

DER:

There is scope for DER participation in a range of nascent flexibility markets, with the nature of the market varying across each DNO's area.

2.5 How do local markets differ from the status quo?

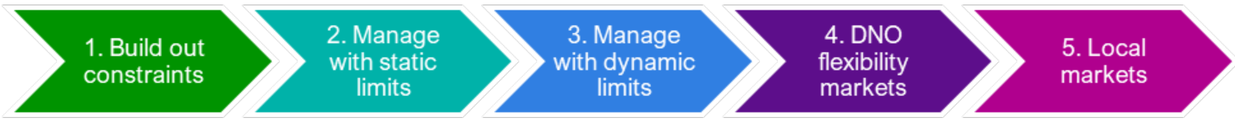
As discussed in section 2.2, the value of implementing a local market is closely linked to the presence of network constraints. If the policy is generally to build out such constraints, the need for a local market approach appears limited – DER can simply participate in existing markets as if they are located at the grid supply point (i.e., the connection point between the transmission and distribution networks).

However, distribution network constraints are becoming increasingly common in some parts of GB. In this context, a local market can be a useful mechanism to ration scarce distribution network capacity and also send price signals consistent with the value in different locations, given network constraints. The local market options considered in this report are one way to achieve that. The alternatives involve the DNO allocating network capacity administratively (through fixed or dynamic export limits) or competitively (through flexibility markets). These alternatives to local markets can (in fact do already) operate with current arrangements.

The various approaches to integrating DER can therefore be placed on a spectrum of more / less sophisticated approaches, with the local market models described in this report sitting at the more complex end. This is illustrated in Figure 4 below and described in Table 2 overleaf.

[30] Ofgem (2022), p. 15.
[31] Ibid.
[32] Ibid.

Figure 4: Spectrum of approaches to managing distribution network constraints



Each of the approaches represent increasing improvement in how accurately and efficiently distribution networks and the resources attached to them are represented in market clearing. The approaches are not mutually exclusive – different approaches can, and indeed are currently, being applied in parallel.

This representation of the different approaches highlights some challenges to assessing how local markets might deliver outcomes that are different from the status quo:

- First, some improvements in DER integration can be realised without introducing a local market model of the type described in this report. For example, DNOs and the ESO are increasingly adopting and refining approaches 4 and 5 below, which will in itself improve the scope for DER to participate in existing markets. Planned initiatives are outlined in section 5.1.
- Second, the status quo is not stable. This means that the ‘gap’ between the benefits delivered by current arrangements and those that could be facilitated through a local markets approach is changing over time.

As illustrated in Table 2, we understand that DNOs currently use or are in the process of adopting various combinations of all the approaches other than a local market. If faced with appropriate incentives to plan and operate their networks efficiently, it could be expected that DNOs may over time develop these approaches (i.e., flexibility markets and dynamic limits) to be as effective as they can be. As discussed in section 5.1.2, funding has been allocated to the DNOs through RIIO-ED2 to further develop DSO capabilities. Accordingly, this future trajectory may be a more appropriate basis to compare the impact of local markets, rather than the outcomes that can be observed today. From this perspective, we can identify the primary potential impacts of local markets as:

- Enabling the most efficient system-wide market clearing solution, across both transmission and distribution level resources. This may deliver incremental gains in the utilisation of both transmission and distribution level resources. At least, under some local market models (i.e., Model 1 and 2) – as illustrated in section 3.5 an approach like Model 3 might not deliver this benefit.
- Providing a consistent definition of responsibilities for dispatch of transmission / distribution network resources through the design of the local market model itself - avoiding the need for primacy rules.
- Potentially, depending on the pricing approach adopted, the provision of sharper locational price signals to distribution-connected resources relative to current arrangements. As discussed in section 3.6.6, this outcome only arises with certain pricing models.

Table 2: Spectrum of approaches to managing distribution network constraints

Approach	Description	Additional impact of each approach
1. Build out distribution network constraints	The traditional approach, whereby the distribution network is progressively upgraded to accommodate new connections. Users might pay a (deep or shallow connection charge) for these reinforcements and/or be required to wait until the works are completed before connecting.	Locational signal provided by connection charges and use of system charges. Allows unconstrained participation of DER in existing markets.
2. Manage constraints with static limits	This approach (and later approaches) allows distribution network constraints to arise as connections grow, but import/exports from the system may be limited if needed to manage constraints. This involves flexible connections, where the DSO places a static limit on exports or imports from a given location (e.g., times when sites can import/export, and/or the import/export capacity).	Flexibility is indirectly rewarded by a faster or cheaper connection process. Compared to approach 1, places constraints on participation of DER in existing markets (which may be justified through cost savings). Static limits may result in efficient use of the distribution network.
3. Manage constraints with dynamic limits	Flexible connections, where the DSO dynamically varies export/import limits for a network user based on real time constraints. Various types of active network management (ANM) schemes are an example of this approach, and increasingly used in GB. Dynamic limits allocate available capacity among users based on an administrative rule – e.g., last-in first-out, pro-rata, or equal sharing.	Compared to approach 2, makes full use of the available distribution network capacity. There may still be constraints on the participation of DER in existing markets, due to uncertainty over what the dynamic limit will be (e.g., this may limit whether a resource can be contracted ahead of time to provide an ancillary service).

Approach	Description	Additional impact of each approach
4. Manage constraints with flexibility markets	DSOs tender for services to manage specific distribution network constraints. DER that obtain a contract are paid to change (or be ready to change) their import/export away from the planned level. In other words, DER is paid to allocate its share of network capacity to another user. Primacy rules are required to determine what happens in the event that activation of a flexibility service by a DSO is in conflict with an instruction provided by the ESO. Developing these rules is a complex challenge and still in progress.	Compared to approach 3, more clearly reveals the value of flexibility in a given location. Unlike approach 3, allocates distribution network capacity between users on the basis of value (as revealed in offers to provide flexibility) – resulting in a more efficient allocation.
5. Local markets	The DMO/TMO hold (or exchange) information distribution/transmission constraints with bids and offers from flexible distribution/transmission resources, and forecast demand/supply from inflexible resources.	Compared to approach 4, facilitates an optimal market clearing solution across both transmission and distribution levels. This is because constraints and resources at both levels are reflected in a single clearing solution, rather than in separate markets. As a result, primacy rules are not required – the local market design inherently defines responsibility for determining which transmission and distribution level resources are dispatched.

3 Local market models

In this section, we introduce the local market models that we have identified as possible options for the GB electricity market. These models are contrasted with the existing market arrangements. Consistent with our terms of reference, the models are described concisely rather than exhaustively.

3.1 Overview

To identify local market models that could be applied in the GB context, we reviewed a combination of academic literature, industry-led studies, and policy processes. The literature on local markets, or adjacent concepts, is substantial – in the order of thousands of papers. We adopted a pragmatic approach for this assignment, described in Appendix A. While not exhaustive, we consider that this approach is likely to have identified the most relevant literature.

Consistent with other reviews of the relevant literature, we found that there is no single definition of a local market.[33] For example, some analyses of local markets focus only on transactions between end-users (e.g., peer-to-peer trading models), without considering interactions with broader electricity markets and the power system as a whole. In light of the REMA objectives, we focused on the literature which discusses local market models that:

- Facilitate active real-time coordination of electricity consumption and supply through the electricity markets (i.e., apply to balancing timeframes, in addition to ahead contracting).
- Respect the physical requirements of the system at both the distribution and transmission network levels and facilitate coordination between the networks (i.e., power system-wide models).
- Provide distribution-connected resources with market price signals which reflect the physical requirements of the distribution system (i.e., a market-based coordination approach).
- Address the role of DER in providing energy and ancillary services to the MO (DMO, TMO, or combined TMO/DMO), as distinct from the provision of services to DNOs.

It is also important to highlight what the local market models discussed in this report are not intended to do. Crucially, the models do not assume that supply and demand can be balanced at all times within a given local area or that actions to meet demand locally have no impact on other parts of the network. Rather, the models aim to provide an integrated approach to balancing supply and demand across the GB power system.

[33] Faia, R. (2022), p.6.

The literature identifies a variety of possible approaches, which can be categorised into three overarching models. While variants exist, these reflect either sub-options or governance differences, rather than fundamental differences in approach:

- Model 1 – Centralised market. This model represents both transmission and distribution level resources/networks in a central market clearing process, run by a single market operator. The key difference from current market arrangements is the explicit inclusion of distribution constraints.
- Model 2 – Layered market. This model seeks to address the mathematical and computational challenges of Model 1 by dividing responsibility for balancing supply and demand between separate distribution and transmission level markets and market operators. Bi-directional communication between the market layers produces a coordinated system-wide clearing solution.
- Model 3 – Two-step market. This model also reflects separate distribution and transmission level markets. Market clearing is sequential, starting with the distribution layer. Unlike Model 2, communication is in one direction, with the distribution market clearing providing a fixed input to the transmission level market.

The three models are presented in sections 3.3 – 3.5. Stylised worked examples demonstrate potential differences in outcomes, relative to current arrangements (section 3.2). As a starting point, the discussion in sections 3.2 – 3.5 first focusses on the models' possible application to the balancing mechanism. We have assumed the real-time market remains a net pool balancing market, although this does not have to be the case. [34]

In principle, the models could (with modifications) also apply to ancillary services and the wholesale market. However, this raises some broader issues beyond just the introduction of local markets, including:

- Whether the wholesale market continues to clear without reflecting network constraints (discussed in section 3.7).
- Whether ancillary services continue to be procured ahead of real-time without co-optimisation with the balancing mechanism (section 3.8).

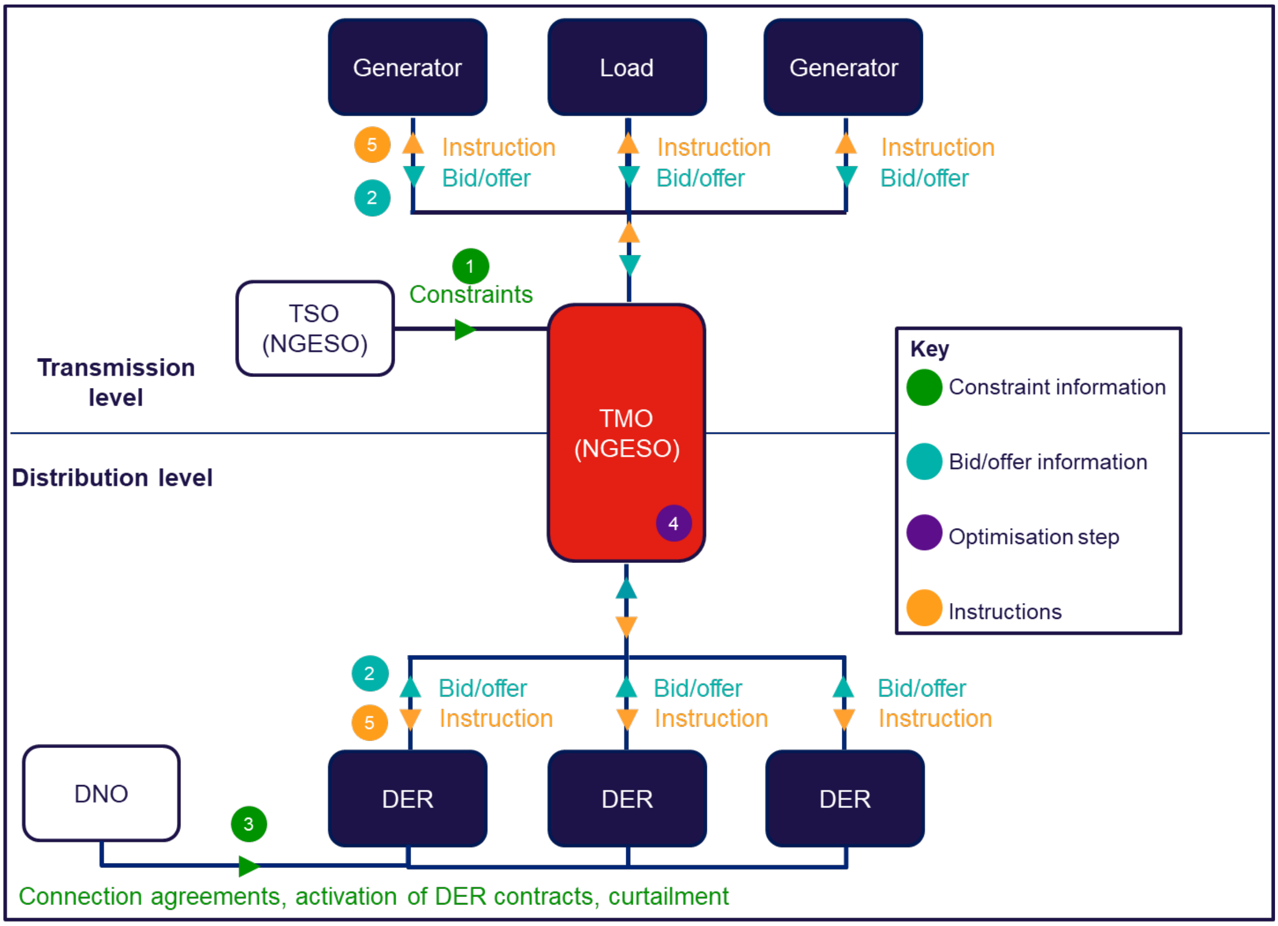
Our literature review identified design elements that would need to be developed to implement any of the models. These are summarised in Table 3. Key differences between the models relate to two elements in particular – bids/offers and market clearing – which are the focus of sections 3.2 – 3.5. For other design elements, no single approach is inherent to any one local market model – rather, there are options that could potentially be considered under all models. We comment on these common design elements / issues in section 3.6.

[34] In a gross pool model, all real-time production and consumption of energy is traded and settled through a central market. Under a net pool model only residual differences in consumption and production, relative to contract positions, are traded and settled through the central real time market.

Table 3: Local Market model design elements

Element	Description
System monitoring	Arrangements for observing network conditions, as an input to market clearing.
Constraint development	Arrangements for describing network constraints, as an input to market clearing.
Forecasting	Arrangements for developing forecasts of non-participating demand and supply, as an input to market clearing. Non-participating resources are those that do not offer their flexibility to the market clearing process and are not given instructions by the market operator. As a result, their consumption / output must be forecast by the market operator (or some other entity).
Participation requirements for DER	DER participation in the local market models may be contingent on certain requirements – for example, related to communication and control, to ensure that resources can receive and respond to instructions from the market operator.
Bids and offers	The form of bids/offers of market participants, and the process for submitting them to the market operator.
Market clearing / optimisation	The process for clearing the market, which involves selecting the optimal combination of resources to balance supply and demand given network constraints.
Price formation	The approach to determining the prices paid by / to market participants as an outcome of the market clearing solution.
Dispatch	Arrangements for the market operator to issue instructions to participants whose bids/offers have cleared. This element relates only to the real-time balancing of supply and demand.
Settlement	Arrangements for the settlement of market participants, on the basis of market prices and their actual electricity consumption / production.

3.2 Status quo



Market clearing sequence	
1	TSO provides constraint formulations to TMO.
2	Controllable generators and loads at transmission / distribution levels provide bids/offers to TMO.
3	DER bids/offers subject to connection agreement, DNO contracts, DNO curtailment.
4	TMO optimises market clearing given transmission constraints, bids and offers.
5	TMO sends instructions to generators and load at the transmission level and DER at distribution level.

High level assessment			
Pros		**Cons**	
✓	Well established.	×	Even if improvements are implemented, limitations on DER participation may persist over the long term.
✓	DNOs and NGESO initiatives indicate that there are opportunities to improve DER integration into existing markets.	×	Current approach is somewhat piecemeal, with many local variations.

3.2.1 Overview

The defining feature of the current balancing market arrangements is that distribution network constraints are not explicitly reflected in the market clearing process. Constraints may be captured indirectly, to the extent that DNOs control DER output via connection agreements or curtailment.

3.2.2 Bids/offers

Market participants submit bids (to increase demand or reduce generator) and/or offers (to reduce demand or increase generation), along with their required price for taking a balancing action. Balancing mechanism bids are submitted at gate closure.

3.2.3 Market clearing process

The TMO selects the combination of balancing bids (and ancillary services) that most efficiently balances supply and demand, while respecting transmission constraints. Cleared balancing mechanism bids/offers receive their bid/offer price (i.e., a pay-as-bid approach).

3.2.4 Worked example

In this section, we set out a stylised worked example of market clearing under the current arrangements. The same example is applied to the three local market models set out below, to highlight differences to one another and the status quo.

It is important to note that the example does not precisely reflect the current imbalance pricing arrangements. That is because:

- The local market models do not necessarily have to follow this approach – rather a variety of pricing options could be considered (section 3.6.6).
- The current balancing market arrangements may change as a result of other reforms being considered through REMA (e.g., the introduction of nodal or zonal pricing). Therefore, the more ‘general’ description provided here may be helpful to highlight fundamental differences to the local market models.
- We have made the following assumptions to make the example simple while still illustrating the key points. In practice these assumptions need not hold, but they do not affect the general conclusions of the discussion:
- All market participants are assumed to actively participate in the transmission-level market operated by the TMO by submitting bids / offers to change their supply / demand and being dispatched accordingly. In practice, some participants may change their supply / demand forecast.
- All market participants are assumed to have a single willingness to pay (in the case of load) or marginal cost (in the case of generation). In practice generators and loads are likely to have more complicated cost / willingness to pay functions. Storage, for example, is unlikely to want to buy at the same price it is willing to sell, due to physical losses of energy from charging/discharging.
- All market participants are assumed to be either load or generation, not storage.
- Losses are ignored.

We have also assumed that participants are incentivised to submit efficient bids / offers (i.e., that reflect their marginal costs or willingness to pay). In practice, participants’ incentives will depend, among other factors, on the pricing arrangements and the level of competition. This is discussed in more detail in section 3.6.6. If bids do not reflect costs / willingness to pay, the market outcome would be sub-optimal to some extent. This might reduce the benefits of any local markets model relative to a scenario where DNOs simply allocate available network capacity using an administrative decision rule (e.g., stage 3 from Table 2 above).

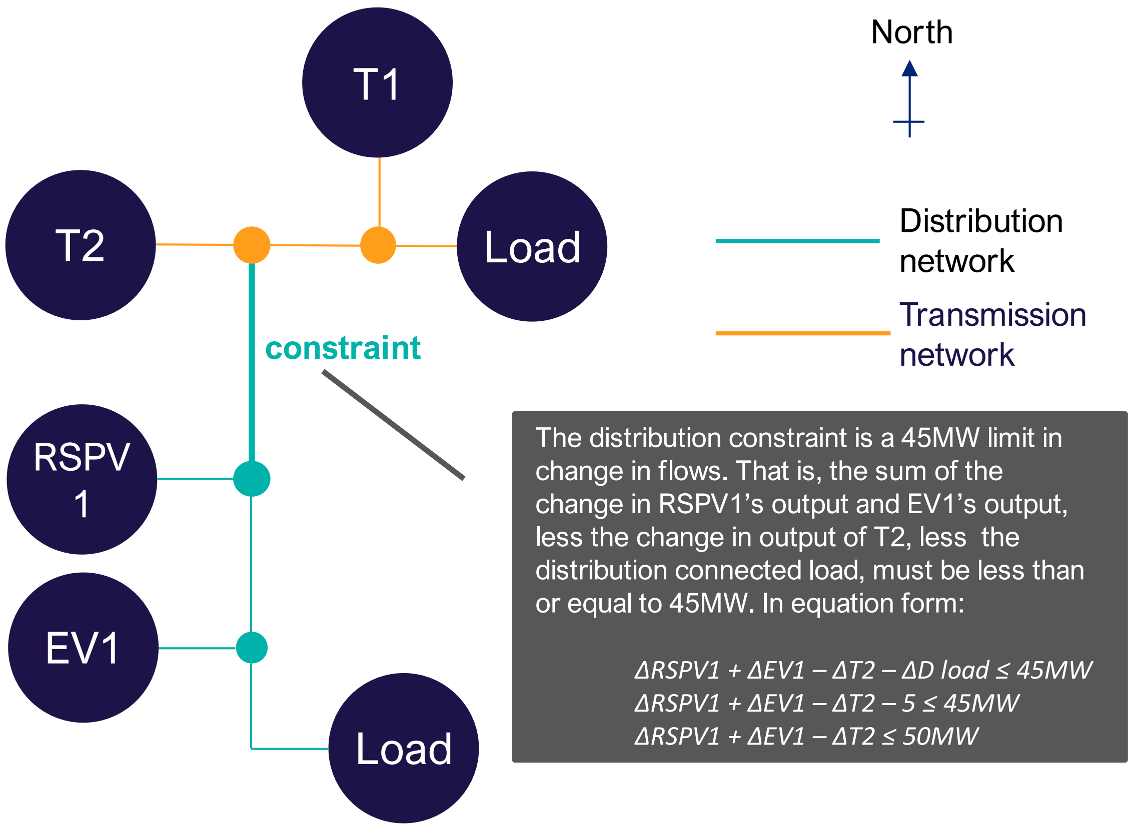
In the worked example, there are four resources, with the following characteristics.

Table 4: Resource characteristics

Description	Name	Cost £/MWh	Maximum increase in supply (MW)
Rooftop solar photovoltaic generator connected at distribution level	RSPV1	5	40
Electric vehicle capable of discharging to grid connected at distribution level	EV1	20	20
Transmission connected generator	T1	100	40
Transmission connected generator	T2	200	20

For simplicity there is only one distribution level network connected to the transmission network. There is a single thermal constraint at the distribution level, which limits the total change in power flow between the distribution and transmission networks to less than 45MW, shown the diagram below.

Figure 5: Transmission and distribution network constraints



In this example, compared to the final physical notifications, total demand has increased by 100MW. 5MW of this increase in demand is at the distribution level, while the other 95MW is at the transmission level.

Although the constraint is at the distribution level, the transmission-connected generator G2 alleviates the constraint. This is because some of its output flows south into the distribution network, offsetting the otherwise northwards flows from the distribution connected generators into the transmission network.[35]

As the limit on the line is a change in output of RSPV1 and EV1 less that of T2 is 50MW, and the DNO cannot be confident about the change in output of T2 at the transmission level, it puts static limits on the change in output of RSPV1 and/or EV1.[36] Let's assume that the DNO sets a static limit on EV1's change in discharge to the grid of 10MW (because at this level RSPV1 can change its output to the maximum (i.e., up 40) even if T2 does not increase its generation). This limit is in turn reflected to the TMO in EV1's offer.

Given the above information about costs, offers and the static limits (as reflected in offers) the TMO determines the solution which minimises costs. It does not, directly, know the distribution constraint. However, the constraint is implicitly accounted for in the bids/offers of the distribution connected resources, consistent with the static limit the DNO has placed on their use of the network.

Table 5: Market clearing outcome - status quo

Name	Offer price (£/MWh)	Offer Δ quantity (MW)	Δ Dispatch quantity (MW)	Δ Cost (£/h)
RSPV1	5	40	40	200
EV1	20	10	10	200
T1	100	40	40	4,000
T2	200	20	10	2,000
Load			**-100**	
TOTAL			**0**	**6**,400

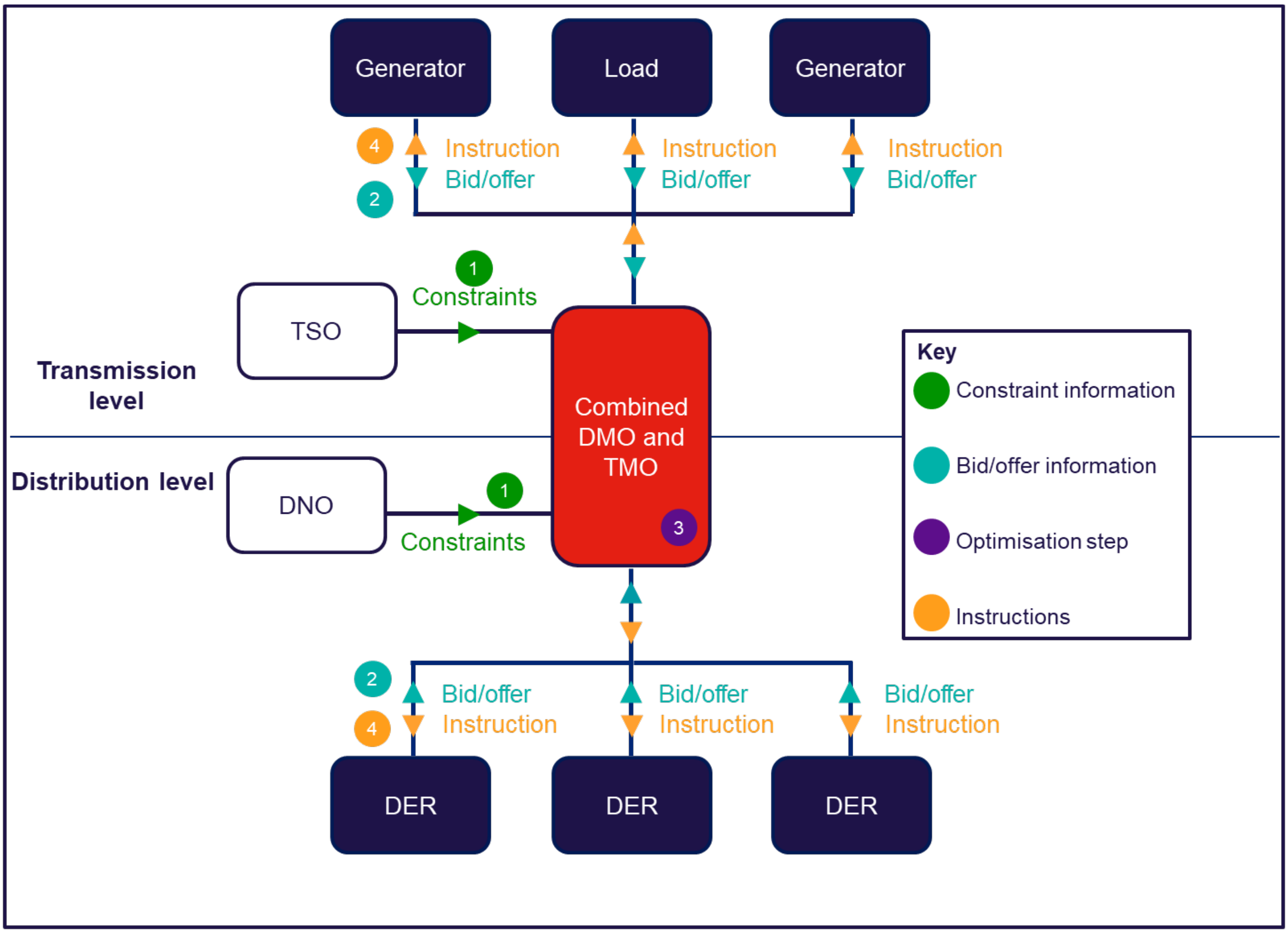
[35] For ease of explanation and arithmetic simplicity, we have assumed that the transmission connected generator G2 participates in the distribution level thermal constraint. In practice, transmission level resources will be more likely to participate in non-thermal constraints at the distribution level, unless there is a loop flow (ie, if the same distribution network resource is connected in two places to the transmission network).
[36] The DNO might alternatively have a contract with RSPV1 and/or EV1 which pays them to limit their change in consumption / generation, with the same effect for the system as setting a static limit.

Inspecting the table above we see that the scenario that the DNO was worried about – T2 not producing enough to alleviate the constraint – does not come to pass. In fact, given the fact that the total generation from EV1 was limited by the static limits, T2 has to increase its output to meet the additional demand at the transmission level. This in turn meant that the distribution constraint is not even at its limit.

The net effect is that the EV1's low-cost generation has been unnecessarily limited, and instead higher cost (and possibly high-emission) generation T2 has been unnecessarily used instead. The magnitude of these inefficiencies is explored when we discuss efficient dispatch outcomes which would arise under models 1 or 2 (below).

The only way to avoid these inefficiencies is for the limits placed on distribution level resources to be set reflecting real-time system conditions. But this is a challenging task under the current market arrangements, given that the optimal limits are a function of the bids and offers of all other generators and loads at both the transmission and distribution level, which the DNO has no knowledge of.

3.3 Model 1: Centralised market



Market clearing sequence	
1	TSO and DSO provides constraint formulations to MO
2	Generator and loads at transmission and DER at distribution levels provide bids/offers to MO
3	MO optimises market clearing given constraints, bids and offers
4	MO sends instructions to generators and load at the transmission level and DER at distribution level

High level assessment			
Pros		**Cons**	
✓	In theory, optimal dispatch	×	Computationally challenging
✓	Economies of scope in combining distribution and transmission market operator roles	×	Information challenge – single MO needs to know T and D level network constraints

3.3.1 Overview

The defining feature of this model is that there is a combined distribution and transmission market operator which simultaneously co-optimises distribution and transmission level resources subject to distribution and transmission level network constraints.

3.3.2 Energy bids / offers

Market participants (or their aggregators) at both the distribution and transmission levels would submit bids and offers to increase/decrease energy supply/demand compared to their final physical notifications directly to the market operator.

3.3.3 Energy market clearing process

The market operator would run a single, integrated security constrained optimisation, taking into account:

- Market participants' final physical notifications at both the transmission and distribution levels (i.e., their planned positions absent any changes in the balancing market),
- Bids and offers from market participants at both the transmission and distribution levels to increase/decrease the supply/demand of energy (and potentially other services) compared to the final physical notifications,
- Information regarding transmission and distribution constraints from the TSO and DSO (and ultimately the TNO and DNO) respectively, and
- Forecasts of the supply/demand of parties that do not actively submit bids and offers into the market (which it may conduct itself or receive from another party).

This would determine the combination of resources which maximises the value of trade of energy (and other services) while ensuring that the network remains within its operating limits at both the transmission and distribution level.

It would then send dispatch instructions to market participants at both the distribution and transmission levels (either directly or to their aggregators) reflecting the outcomes of the optimisation.

In effect, this extends the existing role of the TMO "down" into the distribution level (although the combined role does not need to be played by the existing TMO). Therefore, the key difference to the current market clearing process is the third factor listed above: consideration of distribution network constraints.

3.3.4 Advantages

- Providing the combined market operator has accurate information relating to constraints, and bids/offers reflect marginal costs/values, physical dispatch should be optimal. All resources at both the distribution and transmission level compete on an even footing, given constraints.
- Economies of scale and/or scope arising from combining transmission market operator and distribution market operator roles.
- Compared to the status quo and Model 3, a larger pool of resources may be available to balance supply and demand across the transmission and distribution level. This may have benefits for liquidity and competition.

3.3.5 Disadvantages

- A single, integrated optimisation may be computationally challenging. Compared to the conceptually identical current optimisation at the transmission level, there could be orders of magnitude more market participants and network constraints to take into account.

- Furthermore, lower voltages at the distribution level may restrict the existing use of mathematical simplifications within the current optimisation as it applies at the higher voltage transmission level. It may not just be a case of “adding more” to the current optimisation problem, but instead changing the nature of the algorithm itself to accommodate the lower voltage distribution level. Alternative algorithm designs are unproven in their ability to solve quickly and accurately find the unique optimal solution.
- Relatedly, there is an information challenge: the single market operator would need to have a good and real-time understanding of the distribution networks, constraints, and the resources and demand connected to these networks. This could be potentially orders of magnitude more information to monitor, administer, verify and keep up-to-update.

3.3.6 Worked example

This example takes the same setup as provided as for the status quo, above.

Single integrated constrained optimisation

Given information about costs (as reflected in offers), constraints and demand, the market operator runs a single integrated constrained optimisation. In comparison to the status quo:

- The market operator directly knows the distribution level constraint, and
- Consequently, there is no need for static limits on the change in production or consumption of EV1 (or any other generator or load at the distribution level).

The lowest cost solution which meets the change in demand and respects the network constraint is shown below.

Table 6: Market clearing outcome - Model 1

Name	Offer price (£/MWh)	Offer Δ quantity (MW)	Δ Dispatch quantity (MW)	Δ Cost (£/h)
RSPV1	5	40	40	200
EV1	20	20	15	300
T1	100	40	40	4,000
T2	200	20	5	1,000
Load			**-100**	
TOTAL			**0**	**5,500**

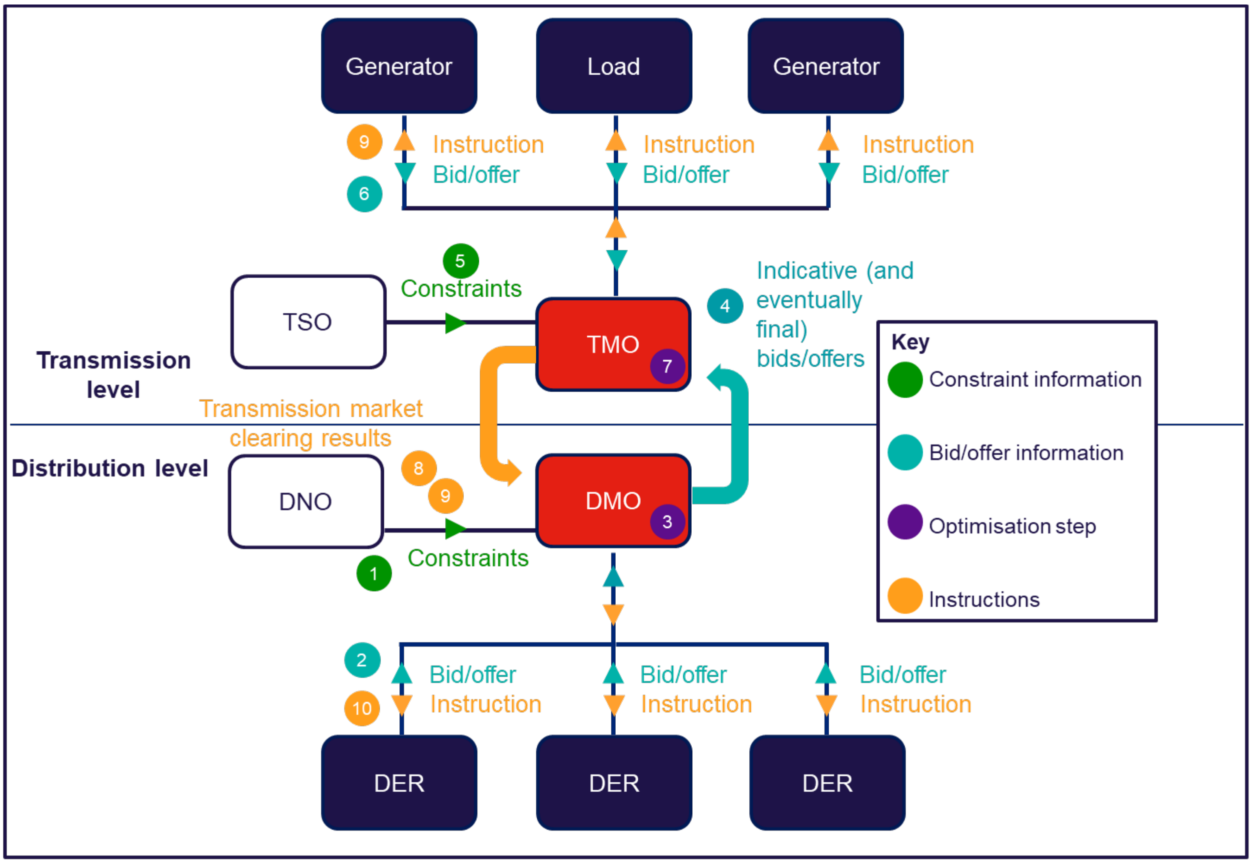
Inspecting the table above, and in comparison to the status quo arrangements, we see that:

- EV1's change in output is 15MW (up from a change of 10MW in the status quo)
- T2's expensive generation is only increased by 5MW (down from a change of 10MW in the status quo).

The market operator sends dispatch instructions directly to each of the five resources (or their aggregators) consistent with these results.

This is the lowest cost combination of resources which can meet the demand given the network constraints, at an overall decrease of cost of £900/h compared to the status quo (the difference in the cost of EV1 and T2 (£180/MWh), multiplied by the change in quantity compared to the status quo (5MW). This is the most efficient physically feasible dispatch outcome.

3.4 Model 2: Layered market



Market clearing sequence

1. DSO provides constraint formulations to DMO
2. DER provide bids/offers to DMO
3. DMO optimises to produce feasible quantity/price pairs
4. DMO submits these indicative price/quantity pairs to the TMO
5. TSO provides constraint formulations to TMO
6. Transmission connected generators and loads provides bids/offers to TMO
7. TMO optimises to initially clear market
8. TMO communicates indicative results to DMO

   Steps 3 - 8 repeat iteratively

9. TMO provides final instructions to DMO and transmission connected generators and load
10. DMO provides instructions to DER

High level assessment

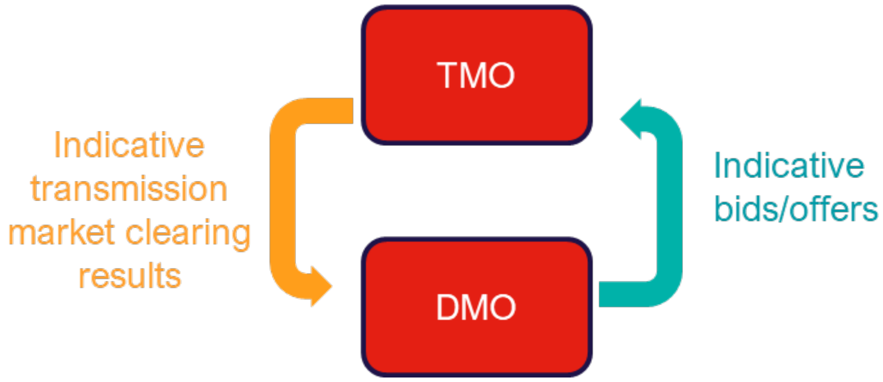
Pros	Cons
✓ In theory, optimal dispatch ✓ Allows economies of scope in combining DNO and/or DSO with DMO roles	× Relies on iterative process to converge on optimal solution

3.4.1 Overview

Under this model, the DMOs and TMO separately but iteratively optimise resources at their respective levels.[37]

The output of the DMO's optimisation feeds is an input into the TMO's optimisation. In turn, the output of TMO's optimisation subsequently changes the inputs for the DMO's optimisation. This process iterates in the lead up to real time, converging on a stable, optimal and feasible solution.

Figure 6: Iterative DMO-TMO exchange



The DMO's role in the transmission level market is to act in a similar way to other transmission connected resources (i.e., generators and loads). That is to say that it provides bids / offers for increases / decreases to energy and other services and, once the TMO has cleared the market, follows dispatch instructions made by the TMO by issuing its own dispatch instructions to DER.

3.4.2 Energy bids / offers

In order to make bids to the TMO, each DMO is informed of market participants' physical notifications at both the transmission and the distribution level. It receives bids and offers from DER to change their consumption or production versus these notifications, and information about distribution level constraints relating to its distribution network. It makes initial assumptions about the expected change in dispatch quantity[38] of transmission level resources which participate in distribution level constraints compared to the physical notifications. In order to complete the picture, it will also need forecasts of non-controllable distribution level resources, which it may make itself or receive from another party.

Given the above information, each DMO calculates a single indicative bid/offer stack (known in the literature as "generalised bid functions") for changes in injections / withdrawals to / from the transmission network. It provides this to the TMO in the lead up to real time (perhaps 24 hours ahead). That is, it provides:

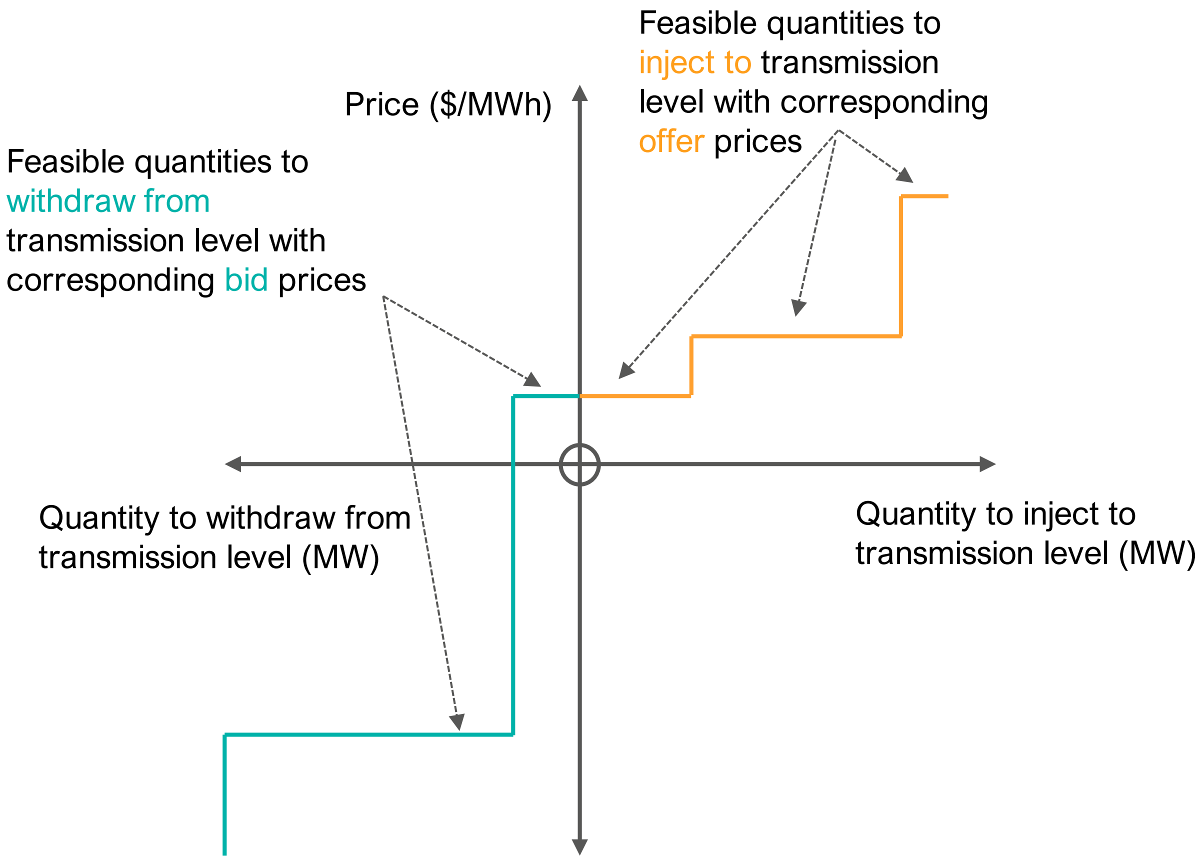
---

[37] Examples of this model can be found at: Farrokhseresht et al. (2020), Tohidi and Gibescu (2019), Yuan et al. (2016), Caramanis et al. (2016), Burger et al. (2019), and Energy Networks Australia (2020), pp. 29-30.
[38] It could alternatively estimate the prices at which transmission resources bid/offer at and use these to infer quantities.

- a series of quantities that can be injected to or withdrawn from the transmission network at the relevant grid supply point. Each quantity provided is physically feasible at the distribution level given the bids and offers from DER, network constraints, forecasts of non-controllable resources, and assumptions about transmission level resources
- a corresponding series of prices (i.e., one price for each quantity) which reflect the marginal cost of providing/receiving the quantity in question to/from the transmission system.

This bid/offer stack is illustrated in the figure below.

Figure 7: Illustrative DMO bid/offer stack



Importantly, the bid/offer stack provided by the DMO to the TMO is not a “raw” summation of the bids and offers made by the DER, but instead is processed by the DMO to reflect distribution level constraints. That is, for each quantity step offered, the price represents the optimal marginal cost, as determined through an algorithm operated by the DMO.

As now, the TMO also receives physical notifications from generators and load connected at the transmission level (24 hours, say, ahead of real time), and may also forecast non-controllable resources at that level.

3.4.3 Energy market clearing process

At some point before real-time (for example, an hour ahead), the TMO runs a security constrained optimisation, reflecting:

- The physical notifications of transmission level resources and each DMO
- The indicative bids/offers to increase or decrease supply or demand from each of the DMOs, as determined in the process outlined above
- The indicative bids/offers to increase or decrease supply or demand from transmission level generators and loads
- Forecasts of non-controllable transmission level resources
- Transmission level constraints.

Note that the TMO does not – directly – need information on the distribution level constraints, or individual DERs. Instead, this information is embedded in the bids/offers of the DMOs. This is analogous to the TMO not directly needing information on the nuts and bolts of a generator; instead, the generator provides offers which are in the format that the TMO requires to run its optimisation process and which embed the detailed information about the generator's plant. In this sense, the DMO is acting like a flexible load or generator, with an initial intended export/import from the transmission network and the potential to be turned up and/or down within a certain range.

Based on the information listed above the TMO will determine an indicative set of dispatch instructions for transmission level generators and loads, and the DMO.

To the extent that the DMO's original estimate of the change in output of transmission level resources that participate in distribution level constraints does not correspond to the TMO's dispatch instructions for those resources, the dispatch is likely to be either sub-optimal or infeasible (or both). Consequently, informed by indicative market outcomes provided by the TMO, the DMOs can adjust their bid/offer stacks to better reflect the expected transmission level resources, and resubmit these updated bid/offer stacks to the TMO.

The TMO then re-runs its optimisation, potentially resulting in a different combination of indicative dispatch instructions to the transmission level resources and the DMOs.

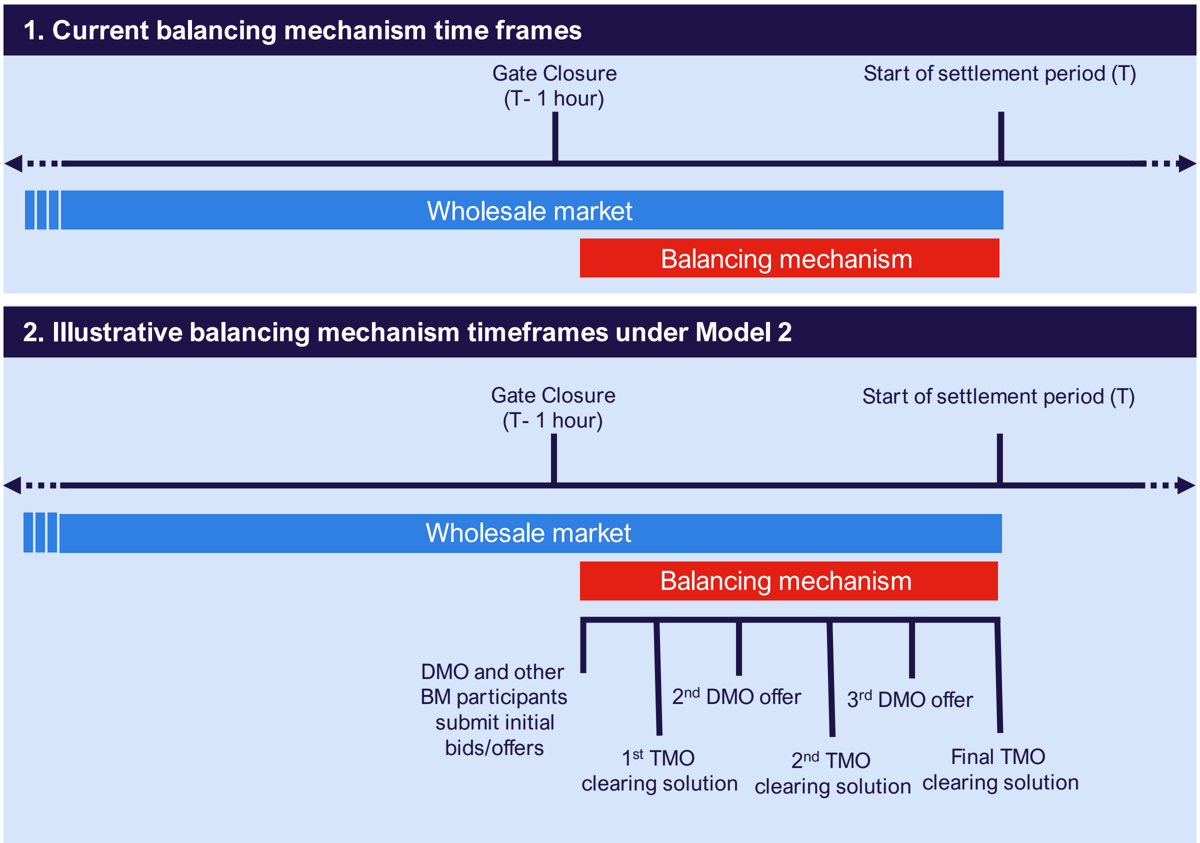
This process then iterates, with the DMOs (and transmission level resources) updating their bid/offer stacks given the TMO market outcomes and any changes in expected real-life conditions (such as the weather), with the TMO re-running its optimisation process given the updated bid/offer stacks. DER may also be allowed to update their bids/offers to the DMO to reflect changes in conditions. Over the period of time between the first run and real time, the process – it is hoped – converges on stable solution which is feasible and optimal.

In principle, the number of layers in this process can be more than two. For example, a layer below the DMO could be included (e.g., for microgrids), with a series of microgrid market operators providing collated bid/offer stacks to the DMOs.

As described above, the DMO "goes first", based on an initial estimate of the outcomes at the transmission level. As the solution is found iteratively, it is alternatively possible that the TMO "goes first" instead, making assumption about outcomes at the distribution level.

An illustrative description of the potential timing of these steps is shown in the figure below. The timeframes shown are speculative and intended to indicate a possible sequence of events. Our literature review did not identify any concrete evidence of how long such a process might take, or how many iterations would be needed.[39] Interactions with the detail of the ESO's current process to determine which balancing actions to accept would also need to be considered.

Figure 8: Illustrative balancing mechanism process under Model 2



3.4.4 Advantages

- In theory, this model should result in the same, optimal solution as in Model 1.
- By breaking down the optimisation problem into smaller chunks, this may address the practical concerns relating to Model 1. That it, it may result more practical optimisations processes, and address information administration challenges. For example, Model 2 could potentially allow different DMOs to use their own methodology to determine the bid/offer stack shared with the TMO (provided that the resulting bids/offers are all feasible from a distribution system perspective). It may be the case that a simpler

[39] We did identify one paper expressing the view that this type of iterative approach *would* require an infeasibly long time to reach equilibrium (although the reasons / evidence where not fully explained). A modification to the model was proposed to address this: namely that in its first run, the DMO could produce proposed injections / withdrawals and bid/offer curves for a variety of alternative transmission market outcomes – potentially reducing the number of iterations required. However, the paper did not indicate how many alternatives the DMO might need to generate, not what impact this process would have on the time needed for the DMO to clear its market. Further details can be found in Tohidi et al (2019).

approach could be adopted in parts of the network that have fewer or less complex constraints. Model 2 could be a more practical approach than Model 1.

- Compared to Model 1, enables economies of scope and/or scale from combining distribution network owner and/or distribution system operator with market operator role.
- Data privacy issues may be somewhat ameliorated as new information is submitted between the DMO and TMO and is "packaged up", and therefore does not reveal individual consumer behaviour or preferences.
- Different DMOs may be able to take different approaches to their own optimisation problem. This could give rise to more innovative and superior solutions than Model 1, which relies on a single entity.

3.4.5 Disadvantages

- This model relies on the iterative process converging on a result quickly enough ahead of real-time. If convergence on the efficient equilibrium cannot be achieved in the required timeframe, the results could be suboptimal at best or infeasible at worst. In this scenario, a suboptimal result could occur because the need to reach a clearing solution within a given time frame might force an approximation of the efficient outcome. For illustration, in the worked example below, this might mean stopping at the second iteration – which is not the optimal clearing solution.
- Multiple entities would be required to develop and maintain MO capabilities (e.g., systems and processes to managing the market clearing).

3.4.6 Worked example

This example has an identical physical set up as for the status quo and Model 1.

Iteration 1

The DMO makes an initial assumption about the change in quantity of T2 that it expects will subsequently be dispatched by the TMO. Based on previous experience (noting that this is a repeat game each settlement period), we assume that the DMO forecasts that G2's change in output will equal 0MW.

Given this assumption, the constraint, and the offers from RSPV1 and EV1, the DMO provides an indicative bid/offer curve to the TMO:

- It bids to buy 5MW more energy from the transmission system at a price of less than £5/MWh. That is, it would be happy to purchase 5MW more energy from the transmission grid at price less than £5/MWh, as this would be cheaper than utilising RSPV1.
- It offers to sell 35MW more to the transmission system at £5/MWh. 35MW represents the maximum possible increase in output from RSPV1 net of the quantity required to service the 5MW increase in local demand on the distribution grid. £5/MWh is the marginal cost of this net injection to the transmission system (i.e., the cost of RSPV1).

- It offers to sell a further 10MW (i.e., between 35MW and 45MW) at £20/MWh, representing the marginal cost of EV1.

It does not offer to sell to inject more than an additional 45MW because that is the physical limit of the line between the distribution and transmission network. It does not bid to buy more than another 5MW because doing so would exceed the change in local demand on the distribution network (and, in this example, RSPV1 and EV1 have not offered to reduce their supply or increase their demand).

Given these offers from the DMO, and in combination with the offers from T1 and T2, the TMO now optimises dispatch. Note that in comparison on Model 1, the TMO is only concerned with optimising dispatch to meet the change in transmission level load (95MW).

As we have assumed there are no transmission constraints, and there are no transmission level resources offering at prices less than £5/MWh the solution is straightforward: the TMO selects the cheapest offer first, then the next cheapest, and so on, until demand is met.

Table 7: TMO clearing outcome - Iteration 1

Name	Offer price (£/MWh)	Offer Δ quantity (MW)	Δ Dispatch quantity (MW)	Δ Cost to serve T level load (£/h)
DMO offer 1	5	35	35	175
DMO offer 2	20	10	10	200
T1	100	40	40	4,000
T2	200	20	10	2,000
T level load			-95	
TOTAL			**0**	**6,375**

Note that the TMO is not (directly) reflecting the distribution constraint in its optimisation algorithm.

Importantly, the market participants are not dispatched based on this initial iteration. Instead, the outcomes of this iteration fed back to the DMO.

Iteration 2

The DMO sees that its estimation of T2's change in output was wrong. It assumed a change of 0MW when the information from the TMO suggest 10MW is more appropriate. While the solution is physically feasible it is not economically optimal. So, the DMO updates its estimate of T2's change in output to +10MW, reflecting the results from the TMO.

Given this, it now revises its bid/offer curve to the TMO. Now it offers:

- As before, it bids to buy up to 5MW more energy from the transmission system at a price of less than £5/MWh.
- As before, it offers to sell 35MW more at £5/MWh
- Unlike interaction 1, it offers to sell a further 20MW at £20/MWh (up from 10MW at this price).

It does not offer any capacity above a change of 55MW (up from 45MW), because, having assumed T2's change in output will be 10MW, and taking into account the 5MW change in local demand on the distribution level, it is not feasible to offer more than 55MW more injections because of network constraints.

Given these revised offers from the DMO, and in combination with the offers from T1 and T2, the TMO now re-solves. Again, the solution is simple because there are no transmission level network constraints: the TMO selects the cheapest offer first, then the next cheapest, and so on, until demand is met.

Table 8: TMO clearing outcome - Iteration 2

Name	Offer price (£/MWh)	Offer Δ quantity (MW)	Δ Dispatch quantity (MW)	Δ Cost to serve T level load (£/h)
DMO offer 1	5	35	35	175
DMO offer 2	20	20	20	400
T1	100	40	40	4,000
T2	200	20	0	0
T level load			-95	
TOTAL			**0**	**4,575**

The changed in the cost to serve T level load quantity for the DMO's highest offer is highlighted in bold.

This is a lower cost solution, but it is not feasible because the DMO's estimate of T2 change in output is now too high (it assumed 10MW when the TMO's result suggests 0MW).

Iteration 3

The dispatch information from the TMO is again then fed back to the DMO to revise its offer curve.

The DMO knows 0MW is too low an assumption for the change in output for T2, resulting in a feasible but inefficient dispatch, and that 10MW is too high, resulting in an infeasible dispatch. On this basis, it knows the least cost feasible answer for T2's change in output is somewhere between 0MW and 10MW. Let's assume it now splits the difference and estimates 5MW.

It revises its highest priced offer to be 15MW at £20/MWh (down from 20MW in iteration 2, but above 10MW in iteration 1).

The TMO once again solves, with the following results.

Table 9: TMO clearing outcome - Iteration 3

Name	Offer price (£/MWh)	Offer Δ quantity (MW)	Δ Dispatch quantity (MW)	Δ Cost to serve T level load (£/h)
DMO bid 1	5	35	35	175
DMO bid 2	20	15	15	300
T1	100	40	40	4,000
T2	200	20	5	1,000
T level load			-95	
TOTAL			**0**	**5,475**

The DMO estimate of T2's change in output has converged on the TMO's result for T2's change in output.

Having iterated to the solution, the TMO sends dispatch instructions to T1 (40MW), T2 (5MW) and the DMO (50MW in total), which serves the transmission level change in demand of 95MW.

The DMO then sends dispatch instructions to RSPV1 (40MW) and EV1 (15MW), 5MW of which serves the change in local demand, and the remaining 50MW of which meets the TMO's instructions. The final clearing outcome, which represents the overall solution, is outlined in the table below.

Table 10: Final clearing outcome

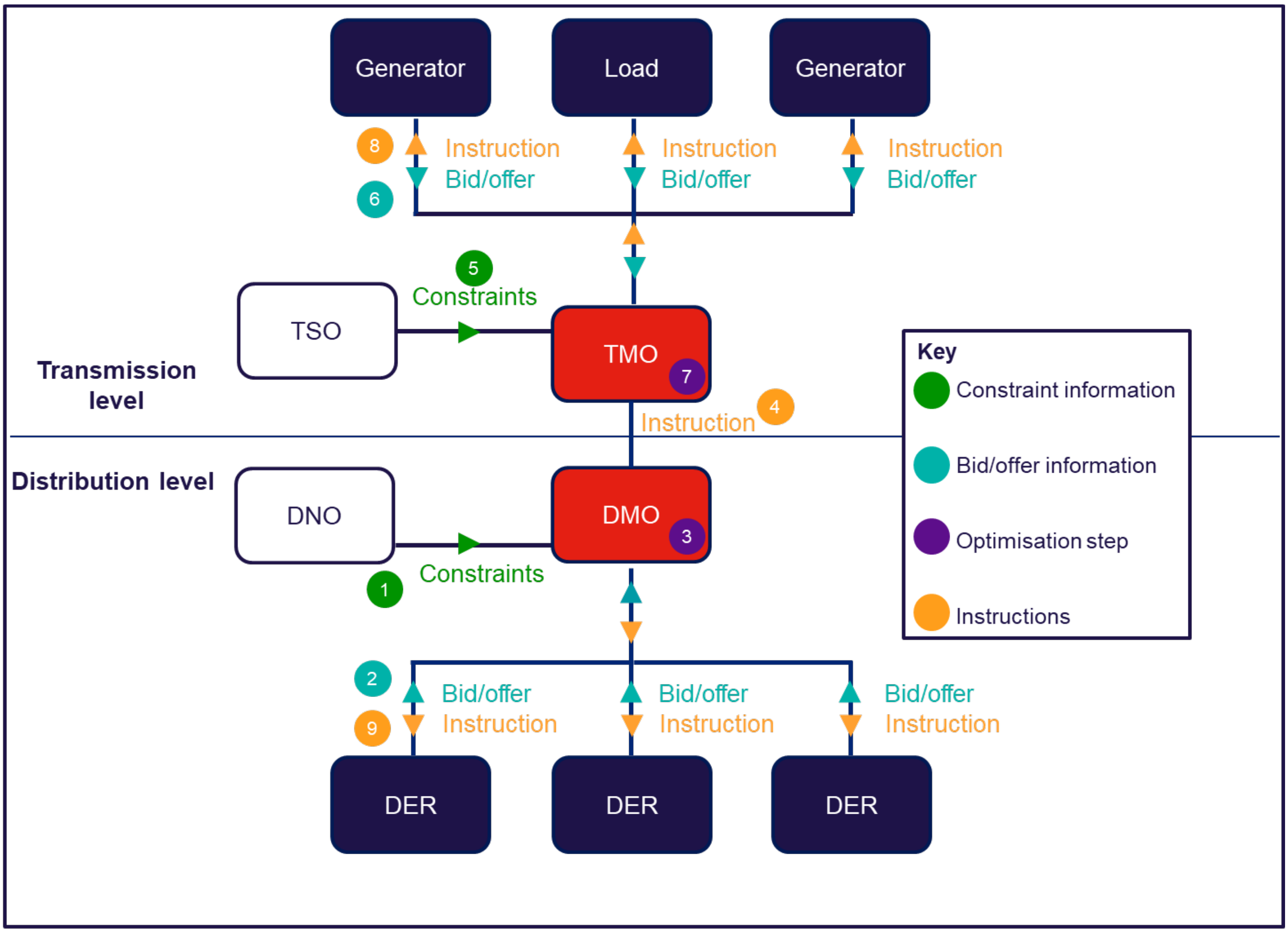
Name	Offer price (£/MWh)	Offer Δ quantity (MW)	Δ Dispatch quantity (MW)	Δ Cost to serve T level load (£/h)
RSPV1	5	40	40	200
EV1	20	20	15	300
T1	100	40	40	4,000
T2	200	20	5	1,000
Load			**-100**	
TOTAL			**0**	**5,500**

This solution respects the distribution level constraints and maximises the value of trade.

Note that this is the same overall solution as Model 1. In Model 1, RSPV1 and EV1 offer 40MW and 20MW respectively (i.e., more than 55MW between them), but the single market operator only selects 55MW in order to respect the constraint in the least cost way.

In contrast, in Model 2, the interaction between the results from the TMO's dispatch and the DMO's offers results in the DMO only offering the TMO 50MW more in total between RSPV1 and EV1. The TMO then selects this combined total of 50MW to be injected from the distribution network to the transmission network, and the TMO then instructs the DMO to do so. The DMO in turn instructs RSPV1 and EV1 to dispatch 55MW more, 5MW which meets the change in local demand while the remaining 50MW meets the TMO's dispatch instructions.

3.5 Model 3: Two-step market



Market clearing sequence
1 DSO provides constraint formulations to DMO
2 DER provide bids/offers to DMO
3 DMO optimises to maximise distribution level resources
4 DMO submits to TMO instructions of injections/ withdrawals to be made to transmission network
5 TSO provides constraint formulations to TMO
6 Transmission connected generators and loads provides bids/offers to TMO
7 TMO optimises to clearing market
8 TMO provides instructions to transmission connected generators and load
9 DMO provides instructions to DER

High level assessment

Pros	Cons
✓ Simpler than models 1 and 2: avoids highly complex single algorithm in model 1 and iterative process in model 2.	× Does not co-optimise distribution and transmission level resources: inefficient use of resources

3.5.1 Overview

Each DMO undertakes a constrained optimisation process, either by taking account of only distribution level resources and constraints, or by making a set of assumptions about transmission level resources and constraints. This will determine a net change in injection / withdrawal to / from the transmission network.

It then passes the results of this optimisation to the TMO. The TMO then undertakes its own optimisation of transmission level resources, taking as a given the results from the DMOs.

3.5.2 Energy bids / offers

At the distribution level, DER make bids / offers to the DMO to change their energy demand / supply compared to their final physical notification.

Equivalently, at the transmission level, generators and load make bids / offers to the TMO to change their energy demand / supply.

3.5.3 Energy market clearing process

Each DMO has information regarding:

- Distribution level market participants' final physical notifications (i.e., their positions absent any changes in the balancing market)
- Bids and offers from market participants at the distribution level to increase/decrease the supply/demand of energy (and other services) compared to the final physical notifications
- Information regarding distribution constraints from the DSO (and ultimately the DNO)
- Forecasts of the supply/demand of distribution level parties that do not actively submit bids and offers into the market (and may make these forecasts themselves)

Each DMO clears the balancing market at the distribution level based on the information above. The objective function for this optimiser might be, for example, to maximise the use of DER.

Each DMO would then send to the TMO a statement of net injections or withdrawals that will be made to / from the transmission network. These injections or withdrawals will be feasible, given the distribution level constraints and requirements of transmission level resources. Unlike Model 2, this statement is a single injection/withdrawal outcome – rather than a menu of possible outcomes represented as a bid/offer stack.

The TMO then optimises given all the information that it would normally use (i.e., bids / offers, transmission level constraint equations), but taking as a given the injections / withdrawals specified by each of the DMOs and any transmission level resources required by the DMO to ensure the distribution level optimisation is feasible. In Model 2, the DMO was acting in a similar way to a flexible load or generator, with the possibility to deviate away from their planned withdrawals or injections from the transmission network. In Model 3, the DMO is more akin to an inflexible load or generator.

3.5.4 Advantages

- As a two-stage optimisation process, this avoids the complexity and information challenges associated with Model 1.

- It avoids the problems associated with iterating to a solution that might arise in Model 2.
- As with Model 2, the data privacy issues may be somewhat ameliorated as the information submitted between the DSO and TSO is "packaged up" and therefore does not reveal individual consumer behaviour or preferences.

3.5.5 Disadvantages

- The disconnected two-stage optimisation does not co-optimise transmission and distribution level resources, resulting in inefficient dispatch.
- In effect, this means that transmission-connected resources are not competing with those at the distribution network level.
- This might create stronger incentives for investment in DER at the distribution network level, relative to Models 1 or 2. The overall impact of this model on system costs is unclear:
    - Maximising the use of local resources in real time may not result in the lowest cost or lowest emissions combination of resources that could be achieved, with co-optimisation across the transmission and distribution levels. For example, the TMO might incur costs to manage the impact of the DMO's planned schedule on the transmission system, which would not be visible to the DMO when clearing its market.
    - It is possible that greater development of resources that can meet local energy requirements might over time reduce the need for network reinforcements between the transmission and distribution levels. However, if more DER is encouraged onto the system as a result of the market design, this may prompt a need for additional distribution network upgrades.

The overall impact on efficiency will depend on complex interactions between price signals faced by transmission- and distribution-connected resources, their relative costs, and the network developments that would be needed under alternative pathways of DER uptake. Quantifying these effects is beyond the scope of this report. However, it is important to emphasise that maximising the use of local resources is not inherently efficient – even through transmission infrastructure is needed to move electricity between the local and national levels, this is not sufficient to conclude that local energy balancing would be less costly overall.

3.5.6 Worked example

An identical physical set up is assumed as for the status quo and Models 1 and 2.

Step 1: DMO optimisation

In this case, the DMO is seeking to maximise the use of distribution level resources.[40]

[40] There might be alternative objective functions, such as minimising distribution level costs.

There are two ways things could proceed from here. In the first, the DMO selects all of D1's and D2's offered change in output (60MW in total), nets off local change in demand, and then provides instructions to the TMO that:

- The combined changed injections from the distribution network to the transmission network will be 55MW, and
- The TMO must commit T2 to at least 10MW of increased output in order to respect the distribution level constraint.

Step 2: TMO optimisation

The TMO, taking account of this information, then optimises. As with model 2, it is only interested in transmission level change in demand, which is 95MW. From its perspective the constraints are as follows:

- It must increase supply equal to 95W, but the increase in supply from the distribution level must equal 55MW, so the increase in supply from the transmission level must equal 40MW
- At least 10MW of that increase in supply must by from T2.

Given these constraints, it optimises. As T1 is cheaper than T2, the solution is trivial: T1 increases output by 30MW and T2's by 10MW.

The TMO dispatch outcome is shown in the table below.

Table 11:TMO dispatch outcome

Name	Offer price (£/MWh)	Offer Δ quantity (MW)	Δ Dispatch quantity (MW)	Δ Cost to serve T level load (£/h)
DMO instructions	N/A	N/A	55	N/A
T1	100	40	30	3,000
T2	200	20	10	2,000
T load			**-95**	
TOTAL			**0**	**5,000**

The TMO sends instructions to T1 and T2 accordingly, while the DMO sends instructions to RSPV1 and EV1 consistent with its original instructions. The overall outcome is shown below.

Table 12: Overall dispatch outcome (scenario 1)

Name	Offer price (£/MWh)	Offer Δ quantity (MW)	Δ Dispatch quantity (MW)	Δ Cost to serve T level load (£/h)
RSPV1	5	40	40	200
EV1	20	20	20	400
T1	100	40	30	3,000
T2	200	20	10	2,000
Load			**-100**	
TOTAL			**0**	**5,600**

Note that this is a feasible but sub-optimal solution. Maximising the output of the cheap resources at the distribution level has – somewhat counter-intuitively – not resulted in the overall cheapest dispatch because doing so necessitated excess use of the most expensive resource in the system, T2, due to the constraint. Compared to the efficient outcome of models 1 and 2, $100/h of value has been lost.

Alternatively, the DMO assumes that T2 cannot be relied on to alleviate the constraint, and so increases RSPV1's output by 40MW but only increases EV1's by 10MW. It then provides instructions to the TMO that 45MW of additional output will flow from the distribution level (taking into account the 5MW of additional local demand).

The TMO, taking account of this information, then optimises. From its perspective the only constraint is that the change in supply must equal 95MW, but the change in supply from the distribution level must equal 45MW, so the change in supply from the transmission level must equal 50MW.

Given this constraint, it optimises. As T1 is cheaper than T2, the solution is trivial: T1's change in output is 40MW (its capacity) and T2's change is 10MW. It sends these dispatch instructions to T1 and T2. The DMO sends dispatch instructions to RSPV1 and EV1 respectively to increase by 40MW and 10MW, which is consistent with its original instructions to the TMO.

The overall solution, combining the above results with the requirements at the distribution level, is shown below.

Table 13: Overall dispatch outcome (scenario 2)

Name	Offer price (£/MWh)	Offer Δ quantity (MW)	Δ Dispatch quantity (MW)	Δ Cost to serve T level load (£/h)
RSPV1	5	40	40	200
EV1	20	10	10	200
T1	100	40	40	4,000
T2	200	20	10	2,000
Load			**-100**	
TOTAL			**0**	**6,400**

Note that this is the same overall solution as the status quo arrangements (in this specific example – this is not a general finding), and so is suboptimal.

3.6 Common design elements

In this section, we comment on the other design elements that would need to be defined if any of the local market models were introduced.

3.6.1 System monitoring

In any of the market models described above, the DSO will need to actively monitor the performance of network assets (e.g., with equipment measuring power quality, voltage, and current in different parts of the grid) in real time to identify grid issues and ensure that the network operates within its technical limits.[41] In addition, the IT systems the DSO uses to monitor the distribution system will need to provide a detailed and accurate picture of the network at lower voltage levels, in real time.

Traditionally, the relatively predictable patterns of consumption from distribution-connected customers meant that it was possible to manage low-voltage networks effectively without granular monitoring at the low voltage level. Therefore, these capabilities are not yet fully developed, although Ofgem has noted that DNOs in GB are now increasing their network visibility.[42] Trials in Europe in the context of the CoordiNet project highlighted the need to further develop existing tools, or develop new ones from scratch, to allow better monitoring, control, and forecasting functionalities at the distribution level.[43]

Enhanced visibility of individual DER resources would also support system operation and more efficient market outcomes (as well as more accurate settlement and forecasting).[44] Monitoring the delivery of services by DER in real time (including DER that does not actively participate in the market) will help optimise dispatch. In the context of DNO procurement of flexibility services, the ENA has suggested that real-time DER monitoring and dispatch capabilities would facilitate more efficient markets – for example, by avoiding the over-procurement of DER to address the risk that some resources do not respond.[45]

The ENA also noted that some DNOs are trialling real-time automated network re-configuration, where network open points change to re-direct spare capacity where it is most needed. According to the ENA, enhanced visibility of DER will enable more informed switching actions and optimised network performance.[46]

There is currently limited real time monitoring of individual DER in GB (e.g., for real time operational purposes service delivery is assumed unless the DNO is informed otherwise). When available, real-time monitoring of individual services is generally via SCADA

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[41] CoordiNet (2020), D2.2, p. 5. See also Energy Networks Association (2021), p. 25-26.
[42] Ofgem (2022), Future of local energy institutions and governance – Call for inputs, p. 15.
[43] CoordiNet (2020), D2.2, p. 25, 27, and 31.
[44] Data that could be collected from DER installations for monitoring and operation purposes includes physical performance data (current, voltage, active and reactive power, power factor, frequency, power quality), weather data on site (temperature, solar irradiation and angle, wind speed), load factors, level of charge for batteries, availability data (percentage of capacity in service, planned outages), and acknowledgement of control signals. Energy Networks Association (2021), p. 33-34.
[45] Energy Networks Association (2021), p. 23.
[46] Energy Networks Association (2021), p. 26.

(supervisory control and data acquisition). Where DER submit metering data for billing in real time, this can be used to monitor delivery. The ENA concluded that in the longer term there is likely to be an increase in the level of real time monitoring required by system operators.[47]

The ENA has pointed out that collecting real-time operational data from DER connection points and using it for operational visibility and dispatch requires technical components, such as current and voltage transformers, and communication infrastructure.[48] New installations connecting to the network are mandated to have appropriate monitoring and controlling equipment, and the ENA envisions that recommendations to enhance visibility will also be applied retrospectively to existing DERs.[49]

The enhancement of visibility and monitoring capabilities means DSOs will collect large volumes of data in real time from equipment disseminated on the grid, which in turn requires defining and adopting technical requirements and standards for data collection and sharing. Communications and cyber security infrastructure will be needed to support and protect the flow of large volumes of data.[50]

3.6.2 Representation of network constraints

Accurately determining optimal power flows for alternating current networks[51] with a large number of nodes and lines remains a mathematically challenging problem, even for state-of-the-art algorithms. This is because optimal power flows are non-linear and non-convex.[52] Market clearing algorithms need to solve quickly given the physical requirement of the system to be in balance near instantaneously, requiring short settlement periods, yet alternating current optimal power flow (ACOPF) modelling is computationally expensive (and therefore slow to solve), or even intractable for large systems. Furthermore, the solutions found by these algorithms may be materially sub-optimal.

Fortuitously, the physical limitations of a high-voltage alternating current transmission network can be well approximated via direct current optimisation power flow (DCOPF) modelling. The mathematics of power flows on direct current networks does not come with the same computational challenges: the problem is linear and convex, and so quick to solve and – at the transmission level – result in (approximately) optimal solutions. Furthermore, marginal costs associated with constraints can be readily calculated, which are used in the determination of LMPs.

In contrast, the low-voltage distribution network is not as easily approximated by DCOPF, meaning that determining the optimal power flows, and prices to induce efficient responses by

[47] Energy Networks Association (2022b), p. 11.
[48] Energy Networks Association (2021), p. 18.
[49] Energy Networks Association (2021), p. 21.
[50] Energy Networks Association (2018), Appendix 3.
[51] All large power systems, including the GB system, are alternating current networks.
[52] In non-linear systems, the change in some physical outcome (e.g., flows on a transmission line) is not proportional to the change in some other physical input (e.g., the output of a generator). In convex systems, an increase in x will always result in either an increase in y or a decrease in y. In non-convex systems an increase in x will sometimes result in y going up, and sometimes result in y going down.

market participants, is challenging. Addressing this issue is an active (and vast) area of research, including:

- Using alternative approximations to AC power flows which are linear and/or convex (and so readily solvable) but which better represent the physics of the system than DC power flow models; and
- Improving the algorithms for non-linear and/or non-convex problems.

There does not appear to be a consensus in the literature about the best approach, or if any approach is viable.

This issue exists regardless of whether Models 1, 2 or 3 are adopted, although the benefits of Models 2 and 3 include that the optimisation problem has been disaggregated into components each of which is individually smaller and so may be more tractable.

This problem necessarily arises in the balancing market when the physical limits of the system must be represented to ensure safe and secure dispatch. In contrast, in GB's current day-ahead and intra-day markets, transmission constraints are ignored (i.e., not even a DCOPF model is used). This can result in transactions at those times that are physically infeasible, and which must ultimately be unwound in the balancing market. As noted in section 3.7 below, a similar approach could apply at the distribution level (i.e., transmission and distribution constraints could be ignored in ahead-markets, and so avoiding the need for even DCOPF modelling at either level). However, this may negate the benefits of introducing a local model for the wholesale markets.

3.6.3 Forecasting

Shorter and longer-term forecasts of DER behaviour can support network planning, market clearing, and settlement in a number of ways, including developing scenarios for improved outage planning,[53] and calculating baselines against which the performance of DER who offer to vary their demand is assessed.

This section focuses on one specific use of forecasting, namely the need for the market clearing process to take into account forecast consumption/supply from DER that do not actively participate in the market by submitting bids/offers. The predicted behaviour of these resources must be considered alongside the available schedule of bids and offers from market participants and network constraints to ensure the viability and efficiency of the clearing solution – like forecasts of non-participating resources are considered in the current balancing market.[54]

Enhanced visibility and monitoring of the distribution network and individual DER resources would provide data to support more accurate forecasting, both in the longer-term and in operational timeframes. For example, local markets trials in Europe under the CoordiNet

[53] Energy Networks Association (2021), p. 26.

[54] Accurate forecasts of DER behaviour more broadly (actively participating or not) would also facilitate cost-effective operation by improving the scheduling of resources and reducing the use of reserves. Energy Networks Association (2021), p. 27.

program collected hourly predictions of demand at the power system and substation level and of generation by wind and solar parks for different forecasting horizons (e.g., day-ahead, next hour) based on historical load/generation data, real-time readings of weather predictions, calendar information, and technical characteristics of DER units. Power flow analysis was then undertaken based on these forecasts to anticipate potential congestions and constraint violations. This also allowed the DSO to validate and correct bids and/or market clearing results to avoid technical violations in the grid.[55]

In GB, Centrica's Cornwall Local Energy Market (LEM) platform trial included an optimisation algorithm that was designed to allow the DSO to update constraints dynamically following their load/generation forecasting. Although, the trial only used stylised, fixed constraints.[56]

The responsibility for developing the forecasts may be with the DSO or the DMO.[57] Aggregators, suppliers, or individual DER may also contribute to the development of forecasts.[58] For example, as part of the 'scheduled lite' reform proposed by the Energy Security Board (ESB) in Australia, resources could voluntarily opt in to provide self-forecasts of future intentions to the market operator.[59]

3.6.4 Participation requirements for DER

In any of the market models discussed above, DER installations may be required to have certain technical capabilities and meet technical standards to participate in the market effectively.[60] Relevant DER capabilities include:

- Monitoring – Collecting data to assist with system operation (as discussed in section 3.6.1), forecasting (3.6.3), and settlement (3.6.8). This requires that DER installations are fitted with appropriate measuring equipment.
- Communications – Standardised systems and protocols would be required to ensure that DER can submit bids and offers to the market, receive dispatch instructions, and transmit data to the DSO/DMO.
- Control – Receiving and reacting to market signals or instructions, for example altering consumption/supply automatically (i.e., without human intervention) based on dispatch instructions.

[55] See CoordiNet (2020) D2.2., p. 25-26.
[56] Centrica (2020), p. 19.
[57] In the CoordiNet trials, for example, forecasting tools at the distribution level were deployed by the DSO, rather than the TSO, even when the market model being trialled required the TSO to participate in the market for DER. See CoordiNet (2020) D2.2., p. 25, 27, and 31. We note that the CoordiNet project did not draw a clear distinction between system operator and market operator. In other sources, forecasting is a responsibility of the DMO. See for example Farrokhseresht et al. (2020).
[58] The role of these parties in forecasting was highlighted, for example, in Energy Networks Australia (2019), p. 35.
[59] The ESB only envisaged non-financial penalties for inaccurate forecasts. Incentives to participate would include reduced causer-pay allocations of ancillary services costs. ESB (2021), Part B, p. 88.
[60] Energy Networks Australia (2019), p. 28. The ESB (2021), p. 68-69, also noted the importance of consistent technical standards to allow DER owners to switch more easily between service providers (e.g., suppliers or aggregators).

- Interoperability and technical standards – monitoring, communications and control, discussed above, require that IT systems can exchange and make use of information, which in turn may require a degree of hardware or software standardisation.

Requirements such as these have been put in place in local market trials. For example, in the Cornwall LEM trial, participating DER had to be capable of modulating demand/generation when required and providing 30-minute metering.[61]

DER and DNOs in GB currently exchange information via a range of methods, including phone, email, SCADA, and application programming interfaces (APIs). The general consensus is that, in the longer term, APIs will be the primary method for DER to communicate their availability and receive dispatch instructions (with back-up communication methods in place for critical services), although the costs associated with integrating an API might disincentivise less DER participation.[62]

Participation requirements may vary by market. In Farrokhseresht et al. (2020), for example, it is assumed that dispatchable DER can participate in the day-ahead market and the balancing market, while 'stochastic' DER (wind generators) can only participate in the day-ahead market.

In addition to monitoring, communications, and control functionalities, DER installation would be required to provide local markets with products that meet precise technical specifications. The CoordiNet project considered a range of product characteristics, listed in the table below, that DER would have to meet to participate in the market.

Table 14: Examples of DER product requirements

Characteristic	Definition
Preparation period	The period between dispatch and the start of the ramping period.
Ramping period	The period in which the input/output of power is increased/ decreased until the requested amount is reached.
Quantity	The minimum/maximum amount of power (or change in power) for one bid/offer.
Delivery period	The minimum/maximum length of the period of delivery.
Deactivation period	The period for ramping from full delivery to a set point.
Granularity	The smallest increment in volume of a bid/offer.

[61] Centrica (2020), p. 23.
[62] ENA (2022b), p. 9-10.

Characteristic	Definition
Validity period	The period when the bid/offer can be activated.
Mode of activation	The mode of activation of bids/offers (automatic or manual).
Availability price	Price for keeping the product available.
Activation price	Price for the product actually delivered.
Divisibility	The possibility to dispatch only part of the bids/offers, either in terms of power or duration.
Locational information	What locational information needs to be included in the bid/offer.
Recovery period	Minimum duration between the end of the deactivation period and the following activation.
Aggregation allowed	Whether a grouped offering of power that covers several DER units is allowed.

Source: CoordiNet (2019), Deliverable D1.3, p. 25.

Another question relevant to participation is whether individual DER would participate in the market directly or through an intermediary – e.g. a supplier or aggregator could participate in the market on behalf of DER on the basis of a contractual relationship, submitting bids/offers based on a pre-defined ‘strategy’ agreed with the DER owner. While the specific aspects of the supplier/aggregator-DER relationship are beyond the scope of this report, we note that DER participation via an intermediary would raise some detailed implementation questions, for example around settlement.

3.6.5 Voluntary or mandatory participation

A further design question relates to the participation obligations that might apply to local markets. We note that ‘participation’ could be defined differently depending on the context.

In the current GB wholesale market arrangements, participation would relate to the submission of offers to buy or sell energy contracts. In GB currently, we are not aware of obligations on parties to submit offers: forward contracting is rather a voluntary activity.[63] There does not appear to be a clear rationale for changing this approach if a local market model were adopted.

In a balancing mechanism context, different considerations might apply. Here, participation might encompass:

- Submitting forecasts of intended electricity production / consumption into the DMO/TMO's market clearing process (i.e. final physical notifications).
- Submitting contract positions for the purpose of imbalance settlement.
- Submitting balancing bids and offers to reduce/increase energy production/consumption.

Under the current GB market design, generators that have a connection agreement with the ESO are required to submit balancing bids/offers. Smaller distribution connected resources and demand are not required to participate in this way, but may choose to do so. It is possible that in a local markets context, there may be a case for reviewing which type of participants should face similar obligations to large generations in the transmission-level market today. Considerations would likely include:

- The extent to which different resources have sufficient flexibility to make the submission of bids/offers worthwhile.
- Costs for different parties to both develop and submit bids/offers and then comply with the MO's instructions. For example, it may be unreasonable to mandate participation in circumstances where the costs of participation would outweigh the possible revenues.

The submission of contract positions and final physical notifications are activities that would likely still be required under a local market model. The key question here would be which party or parties should be tasked with collating and submitting this information. For example, it may be the case that default responsibility for smaller DER could continue to sit with suppliers. Again, key considerations would include the incidence of costs on different parties.

The literature that we have reviewed on local markets has provided limited direction on these questions. Certainly, advocates of local market approaches tend to emphasise a desire to provide smaller consumers and prosumers with greater choice and control in relation to their participation in energy markets. Adopting an approach that places onerous obligations on these parties would appear to be inconsistent with this perspective.

3.6.6 Energy price formation

There are a wide range of pricing options, and combinations of options, that could potentially be considered. Specifically:

- Pricing could either be pay-as-bid or pay-as-clear. Prices could also reflect average or marginal costs.

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[63] Although in some market contexts, there may be cases where 'market makers' are required to submit bids/offers to improve market liquidity. Such obligations typically fall on larger participants.

- Different pricing approaches could potentially be applied across wholesale, balancing and ancillary services markets.
- Different pricing approaches could be applied at the transmission and distribution level markets. This might depend on the local market design adopted (e.g., combined TMO/DMO functions or separate DMOs and TMO).

The gold standard price formation approach is distribution-level locational marginal pricing (DLMP). DLMPs are analogous to transmission-level LMPs (TLMPs) which have been used for decades in the US and are being considered for GB through the REMA process. LMPs reflect the marginal cost of consuming or supplying energy at a particular location (and, if applied to other services, the marginal cost of those services), taking into account losses and constraints. In the case of DLMPs, this includes losses and constraints at the distribution (as well as transmission) level.

LMPs are a pay-as-clear pricing approach, where a clearing price for each constraint is determined. LMPs are determined endogenously through the dispatch process and reflect market participants' bids and offers. The LMP faced by individual market participants differs by location because individual market participants exacerbate or alleviate different constraints by different amounts. LMPs are calculated in real time by the optimisation algorithm, and so can be determined as "deep" into the network as the constraints that are used in the DMO's optimisation algorithm.

DLMPs could in principle be used in all three market designs described above. Layered approaches (i.e., Models 2 and 3) would involve the TMO determining TLMPs (i.e., the LMP at the distribution-transmission interface) and the DMO determining DLMPs within the distribution network. [64]

DLMPs and TLMPs have desirable properties (assuming no other market failures such as market power, negative externalities etc), for example they:[65]

- Provide incentives for market participants to act in a manner which is consistent with economically efficient outcomes for society as a whole
- Are revenue sufficient: revenue received from consumers > revenue paid to generators, so no need for uplift charges to recover revenue shortfalls.

Despite these advantages, deriving DLMPs that accurately reflect marginal costs may be more complicated than for TLMPs due to the more complex algorithms needed to accurately reflect the physics of the low-voltage distribution network (see section 3.6.2 above). This is an active area of academic research – likely due to the significant benefits of DLMPs should they be workable – with no definitive conclusions. Accordingly, DLMPs remain a theoretical rather than practical concept.

[64] The ESO's most recent analysis of pathways to net zero noted the potential to extend nodal pricing to the distribution network level in future, as conditions permit, with improved monitoring and control at the distribution level and growth in DER. https://www.nationalgrideso.com/document/258871/download, p. 27.
[65] Wang, X. et al. (2022), p.9.

Furthermore, DLMPs may also have practical challenges (some of which may also exist for TLMPs). For example, DLMPs are likely to be volatile and differ radically by location depending on the presence of constraints. This may raise perceptions of inequitable pricing structures. DLMPs (like TLMPs) are also a significant change to existing pricing arrangements, raising the prospect of winners and losers compared to the status quo.

However, a range of alterative pricing arrangements are also possible (from least to most granular):

- A GB-wide wholesale price (that does not reflect transmission constraints), with pay-as-bid pricing at the transmission and distribution levels for balancing (i.e., similar to current arrangements) If this approach is adopted, there would be limitations on the extent to which a local market model would actually deliver improved locational price signals. This is illustrated in the text box below.
- Zonal wholesale transmission pricing (i.e., multiple transmission nodes facing the same zonal wholesale price), with pay-as-bid pricing at the transmission and distribution levels for balancing.
- Nodal wholesale transmission pricing, with all distribution level resources connected to each transmission node facing the transmission nodal wholesale price (i.e., zonal distribution level pricing, with each zone being the entire distribution network "below" to the transmission connection point). Pay-as-bid pricing at the distribution level for balancing.
- Nodal wholesale transmission pricing, with the distribution network connected at each transmission connection point then being sub-divided into zones (i.e., multiple zones per transmission connection point), with each zone being demarked by typically binding distribution level constraints. Pay-as-bid pricing at the distribution level for balancing.
- Nodal transmission and nodal distribution pricing.

Less granular pricing arrangements, while potentially more practical and certainly more familiar in the GB market, are more likely to create perverse bidding and investment incentives. The nature and materiality of these inefficiencies is being actively debated and explored in the context of the potential introduction of nodal pricing for GB. We do not comment extensively here but note that issues considered to apply at the transmission level under the current market could be expected to apply equally in a local markets context, if the status quo pricing approaches are maintained.[66] This might point to a potential compromise between the 'gold standard' DLMP approach, and an approach that improves granularity while still remaining feasible. For example, the second last approach – nodal transmission-level pricing with pay-as-bid pricing for balancing actions to resolve distribution level constraints – could be one option that strikes an appropriate balance.

[66] For example, see Aurora Energy Research, *Impact of locational pricing in Great Britain*, December 2020.

However, we note that the pricing combinations listed above have not been put into practice in a local markets context. Accordingly, more detailed design and validation would be required to confirm their feasibility and understand the incentives that might arise.

Application of current pricing arrangements to a local market

As noted above, the current market design involves:

1. In the wholesale market, a GB-wide price set through exchanges. Network constraints are not reflected in this price.

2. In the balancing market, accepted bids/offers receive their bid price. Parties with an imbalance face a system-wide imbalance price, broadly reflecting a volume weighted average of actions taken to balance supply and demand. Other balancing mechanism costs – including those associated with managing constraints – are recovered through a system-wide charge on demand.

In principle, there are multiple ways that a similar concept could be applied to a local market model.

The first option would be to:

1. Apply the same approach in the wholesale market (i.e., not reflect transmission or distribution network constraints in market clearing and pricing).

2. Apply the same approach in the balancing mechanism. That is, all cleared bids/offers (including at the distribution level) would receive their bid price. Balancing costs would be recovered on an averaged basis, with a system-wide imbalance price.

Clearly, this approach would not offer any improved locational price signals for DER, relative today.

An alternative approach might be to construct a ‘local imbalance pricing approach’. For example:

1. For imbalance settlement, market participants might be required to submit contracts from resources that are located in their local market area. This would prompt the development of contract types at the wholesale market level that are distinguished by location.

And/or:

2. The imbalance price might be calculated as the volume weighted average of balancing actions accepted from resources within a particular local market area.

While these options would produce locationally different wholesale and balancing prices for different parts of the network, the resulting price signals would not be efficient. This is because in practice, balancing supply and demand within a local market area would very likely rely on resources that are located elsewhere on the system. This is because projections of the future power system suggest that by 2035 substantial supply-side resources will remain connected at the transmission network level, and will be used to meet demand across GB.[67] The pricing outcomes described above would not reflect these resources, and therefore ignore the physical system realities. This differs from a LMP approach, where local prices are the product of, and reflect, the overall system clearing solution.

A related question to price formulation is congestion risk management. In international TLMP markets, financial transmission rights (FTRs) are made available and are used to manage the financial risk of congestion on the transmission network. Conceptually, financial distribution rights (FDRs) could play the same role in local markets. However, our literature review did not identify consideration of this as a real option. In practice, we anticipate that there would be substantial practical difficulties in applying such an approach. For example, in US markets FTRs that hedge transmission-level constraints are often allocated to eligible parties through 'simultaneous feasibility auctions'. These auctions aim to ensure that FTRs issue through the auctions are compatible with the expected physical characteristics of the transmission system. This requires judgement on the part of the auctioneer to determine how the future transmission system and associated constraints can be represented in the auction algorithm. Incorporating a huge number of distribution network elements in such a process would likely be extremely challenging and is untested in practice.

Of course, the price signals sent via the local energy market would only be one of a number of price signals faced by DER (as is the case currently at the transmission level). Incentives for efficient operations and investments prompted by sophisticated local market pricing may – in practice – be drowned out by inefficient prices elsewhere in framework. For example, transmission and distribution use of system charges may also warrant reform.

3.6.7 Dispatch

Real time operation at the distribution level requires dispatching assets – i.e., issuing instructions for DER to increase/reduce their supply/consumption of energy in line with system needs (balancing supply and demand in the system in real time and subject to network constraints). [68] A similar concept of dispatch can also be extended to ancillary services.

Dispatch instructions are based on the outcome of market clearing. The dispatch of a market participant is effectively the instruction to execute a bid/offer it has submitted.

To be dispatched, DER must be able to receive and respond to dispatch orders in real time. As discussed in section 3.6.4, this entails some communication and control capabilities. Currently, in the context of flexibility markets, DNOs in GB send instructions to service providers via a range of communication methods – including APIs, phone, email, and SCADA. There is a consensus that APIs will become the primary means of communication in the longer term, as

[67] NGESO (2022), *Future Energy Scenarios*, July, p. 155.
[68] Ofgem (2022), para. 2.15.

this will enable the use of automated systems to process dispatch requirements.[69] In the Australian Open Energy Networks project (2020) it was noted that in the future emerging technology, such as blockchain and artificial intelligence, may also provide ways of delivering dispatchable DER.

Dispatch instructions may be received and executed directly by each DER installation, or by an aggregator/supplier acting on behalf of the DER owner.[70] The party sending dispatch instructions to DER may depend on the market model adopted, and in the literature proponents of similar models have identified different dispatch procedures. For example, in some versions of the centralised market model, the combined MO is responsible for dispatch,[71] while in others it is the DSO who dispatches resources on behalf of the central market/system operator.[72] In descriptions of layered and two-step market models found in the literature, the role of dispatching DER typically sits with the DMO (who, in the layered model, dispatches on the basis of the instructions it receives from the TMO).[73]

While much of the literature that has been reviewed assumes that DER is dispatched in a similar way to resources connected at the transmission level, some local market studies instead assume that DER are not dispatchable[74]. Zhao et al. (2019), for example, assume that DER assets just choose to modify their consumption/production in response to the DLMP. Another example is Nair et al. (2022), where DER receive a ‘commitment score’ which represents their ability to fulfil their contractual commitments and follow the cleared market schedule. This is then reflected in the local market by limiting the scheduling of less reliable DER.

3.6.8 Settlement

In the current arrangements, the financial settlement of transactions that occur in the balancing mechanism involves calculating the difference between metered volumes and contracted volumes for each market participant, applying imbalance prices, and clearing payments from/to market participants for the resulting amounts. Elexon also handles the trading parties’ collateral to ensure their solvency.[75]

Similar actions would be required for financial settlement in local markets.[76] Enhanced monitoring capabilities of individual DER installations would assist with the accurate calculation of imbalance volumes.

[69] Energy Networks Association (2022b), p. 12.
[70] For example, Energy Networks Australia (2020) assumes dispatch via aggregators (p. 26).
[71] Energy Networks Australia (2020).
[72] Kristov et al. (2016); Martini et al. (2015) – both referenced in CoordiNet, D1.3, p. 50.
[73] See for example Farrokhseresht et al. (2020).
[74] In practice, the validity of this assumption will vary for different resources. For example, some loads may be readily dispatchable, especially with sufficient notice.
[75] ELEXON, https://www.elexon.co.uk/operations-settlement/balancing-and-settlement/credit/. Accessed November 2022.
[76] Assuming that local markets are organised as a net pool, like the current balancing mechanism. In a gross pool arrangement, the market price would be applied to the whole amount of energy traded, rather than just imbalances.

The party responsible for settlement in local markets may be the market operator who is also responsible for market clearing and dispatch, or a separate entity (as in the current wholesale market, where the TMO role sits primarily with NGESO, but Elexon is responsible for financial settlement). If dedicated day-ahead/intraday local markets were implemented, financial settlement and clearing could be undertaken by the party that operates the market.

It is worth noting that currently DNOs in GB perform settlement for the services they procure in the flexibility markets they run. [77] However the level of automation in the settlement process varies by DNO.[78]

3.7 Wholesale market

In GB, the wholesale market includes day-ahead and intraday markets, which are exchanges for contracts to buy / sell energy. In principle, the local market models described in sections 3.3 – 3.5 could also apply to these markets.

However, clearing of these markets does not currently take either transmission or distribution network constraints into account. A decision to introduce a local approach for these markets depends partly on whether this feature stays in place (i.e., whether these markets continue to ignore network constraints).

If clearing of the wholesale markets does not include network constraints, there may be limited benefit in considering the introduction of a local market approach for the day-ahead and intra-day markets. This is because a key benefit of the local market models is that they reflect network constraints more accurately than today, and provide opportunities to sharpen price signals[79]. In this context, it may be more appropriate to simply allow DER to participate in the wholesale markets – as is currently being investigated by Elexon. In this scenario, there may still be benefits from introducing a local markets approach in the balancing market.

Alternatively, the day-ahead and intraday markets could be reformed to include network constraints in the clearing algorithm. For example, this is the case in many US markets, where day-ahead markets are administered by independent system operators (ISOs). These markets are based around nodal pricing that reflects transmission system constraints, consistent with the real time markets in these jurisdictions. A similar approach could be taken in GB and extended to the distribution level in the event that a local market model is introduced. However, this would involve substantial changes to current arrangements. In particular, it may not be practical for the day-ahead and intraday markets to be run by independent exchanges. This is because the market clearing process would need to reflect the electricity network topology and constraints, which the balancing market operator(s) would likely be better placed to implement.

[77] Ofgem (2022), para. 2.14.
[78] Energy Networks Association (2022b), p. 11.
[79] Depending on the pricing approach adopted, as noted in section 3.6.6.

Consideration of such reforms to the day-head and intraday markets will also be impacted by broader REMA policy decisions. For example, a decision on whether to pursue nodal pricing in the balancing mechanism may also raise the question of whether these markets should become locational.[80]

3.8 Ancillary services

As noted in section 2.4.3, NGESO currently procures ancillary services contracts in advance of real time. In principle, the local market models described in sections 3.3 – 3.5 could also apply to ancillary services procurement – at least, for those services that are amenable to market-based procurement. This may not be the case for all types of ancillary services. For example, in the Australian National Electricity Market (NEM) the market operator:

- Purchases ‘frequency control ancillary services’ (broadly similar to firm frequency response in GB terms) in real-time markets that are co-optimised with energy.
- Contracts for a range of other ancillary services – where prospective service providers are less numerous (e.g., black start) – ahead of time through competitive tender processes.

An additional consideration, if ancillary service are procured through an integrated transmission- and distribution-level market clearing process, is whether it is possible to standardise services across both network levels.

3.9 Flexibility markets

As described in section 2.4.4, DNOs are starting to contract with DER to manage constraints on their networks. The local market models described in this report could be seen as alternatives to these flexibility markets. Both approaches could potentially operate side-by-side as part of a gradual transition to a local market model. For example:

- In the nearer term, DNO contracting with DER could be used to alleviate distribution network constraints in some areas, while other areas might have a dedicated DMO. In the areas without a DMO, distribution network constraints would need not be included in the local balancing market clearing process, because they would be resolved by the DNO.
- Over time, local market clearing processes could reflect distribution network constraints more comprehensively, meaning that separate DNO-operated flexibility markets would be used less or no longer be needed.

This type of hybrid approach might support a gradual transition to a local market model in the event that not all distribution level constraints could practically be reflected in a local market clearing process from day one (e.g., because DNOs have varying capabilities reflecting the issues present in their local area). However, this type of approach may not produce a system-

[80] CEPA and TNEI (2021).

wide efficient clearing solution, and the potential for conflicting TMO/DNO instructions would need to be carefully considered. Further, a lack of consistency nationally could make these markets harder for DER to engage with – for example, this may be the case for aggregators seeking to roll out their business model at a national level.

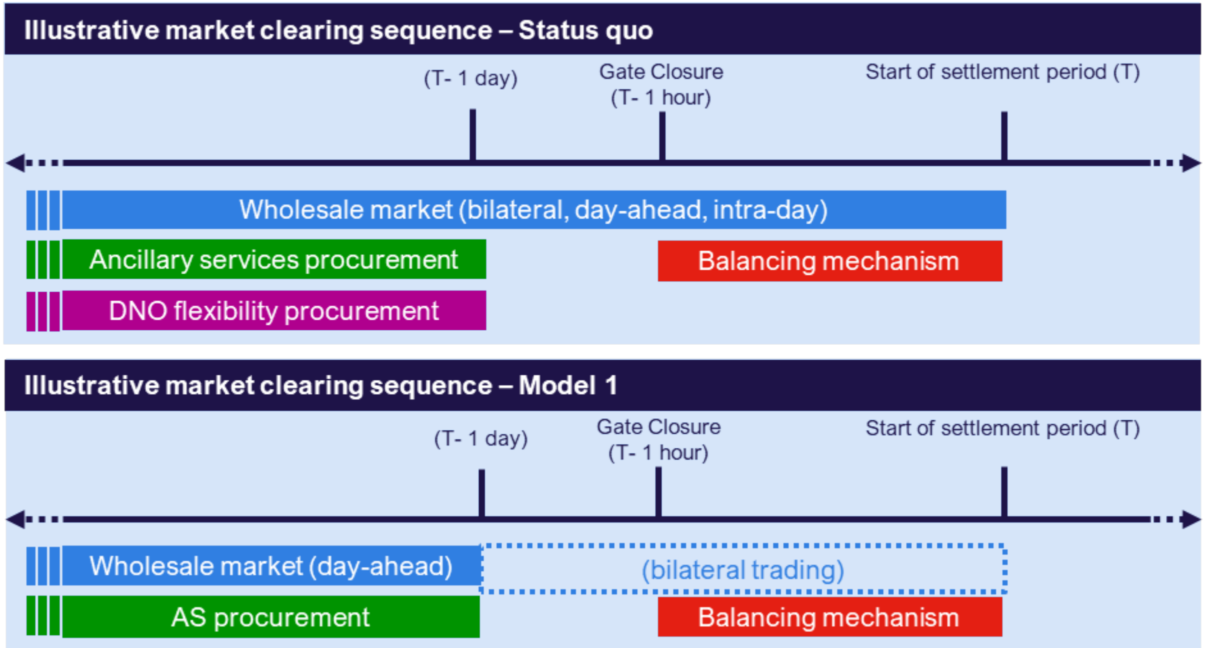
3.10 Linkages between different markets

In the sections above, we have described the possible application of a local market approach to the balancing mechanism, wholesale market, and ancillary services procurement. In principle, it may be possible to adopt a local market model for one or all of these markets. Multiple combinations could be envisaged and further design work would be needed to validate the feasibility, advantages and disadvantages of the different permutations.

To illustrate how a local markets approach might apply across all three markets, the diagrams below provide a stylised representation of how the different markets could potentially clear sequentially. Some key points are that:

- As noted above, if a local markets approach is applied to the wholesale market, this would likely involve a material shift away from the current exchange-led model. The process below assumes, for illustration only, a centralised day-ahead market operated by the DMO/TMO and no intra-day market (although bilateral contracting between parties could in principle continue up to the start of the settlement period).
- In practice, the specific application to ancillary services, and the timing of procurement, will substantially depend on the particular service and potential providers.
- The timings shown are illustrative only. For example, under Model 3 we have not identified specific evidence to support a view that gate closure for the DMO market would need to be 2 hours ahead of real time (although it would need to be before gate closure for the TMO market). Similarly, the number of iterations for Model 2 is not necessarily three.

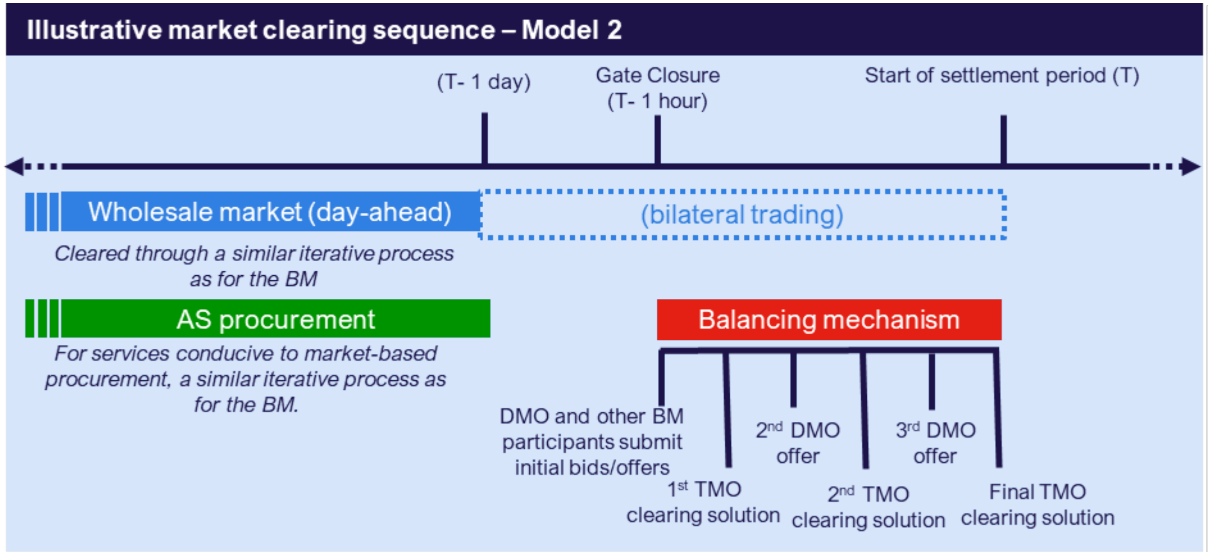
Figure 9: Illustrative market sequencing - Status quo and Model 1



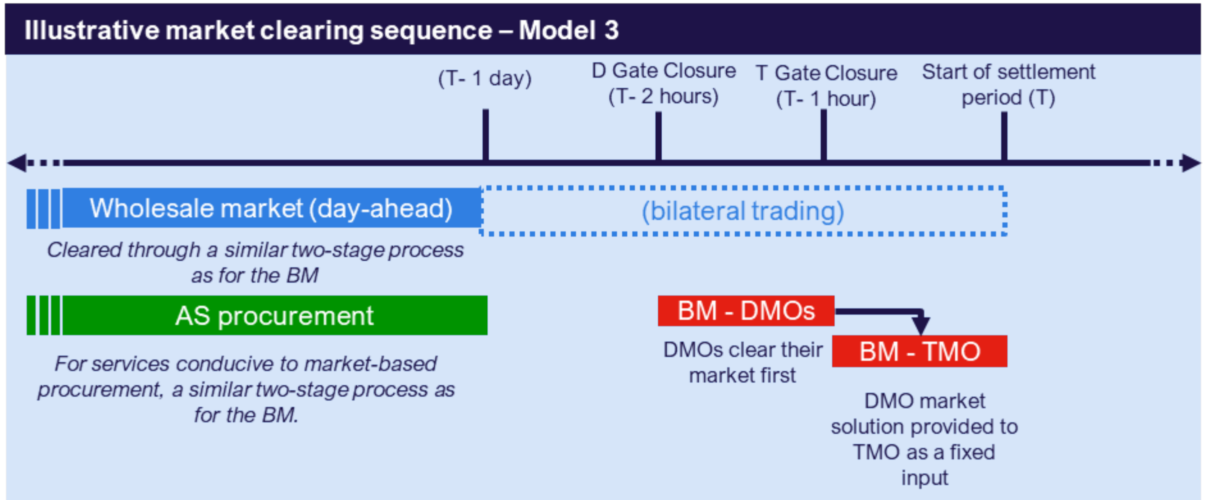
- **Wholesale market** (bilateral trades and exchange-based day-ahead and intra-day) do not reflect network constraints.
- **AS** procured by TMO to meet T-network needs, **flexibility services** procured by DNOs to meet D-network needs.
- **Balancing mechanism** operated by TMO. Reflects T-network constraints directly and D-network constraints indirectly (e.g. limit on imports/exports).

- **Wholesale market** (day-ahead) reflects T- and D-network constraints and is operated by the TMO. Bilateral trades operate in the same was as the status quo, and could continue up to real time.
- **AS** procured by TMO to meet T- and D-network needs.
- **Balancing mechanism** operated by TMO. Reflects T- and D-network constraints directly.

Figure 10: Illustrative market sequencing - Model 2 and Model 3



- **Wholesale market** (day-ahead) consists of a T-level market (reflecting T-network constraints and operated by the TMO) and D-level markets (reflecting D-constraints and operated by the DMOs). The market clears based on an iterative process between the T- and D- markets. Bilateral trades same as status quo..
- **AS** procured by the TMO to meet T-network needs and the DMO to meet D-network needs. A similar iterative process to the wholesale market and balancing mechanism is used. The approach may need to be adapted depending on the service, and number of possible providers.
- **Balancing mechanism** operated by TMO and DMOs, with a similar iterative process as described for the day-ahead market above.



- **Wholesale market** (day-ahead) consists of a T-level market (reflecting T-network constraints and operated by the TMO) and D-level markets (reflecting D-constraints and operated by the DMOs). The market clears based on a two-stage process, with the DMO market clearing first. Bilateral trades same as status quo..
- **AS** procured by the TMO to meet T-network needs and the DMO to meet D-network needs. A similar two-stage process to the wholesale market and balancing mechanism is used.
- **Balancing mechanism** operated by TMO and DMOs, with a similar two-stage process as described for the day-ahead market above.

4 Assessment of the models

In this section, we provide a qualitative assessment of the models' benefits and risks.

4.1 Benefits

Our review of the literature has identified estimates of the benefits of improved DER integration generally, but less specific evidence in relation to the benefits of local markets specifically. In this section, we summarise relevant evidence in relation to DER integration benefits, and then consider what the incremental contribution of a local markets approach might be.

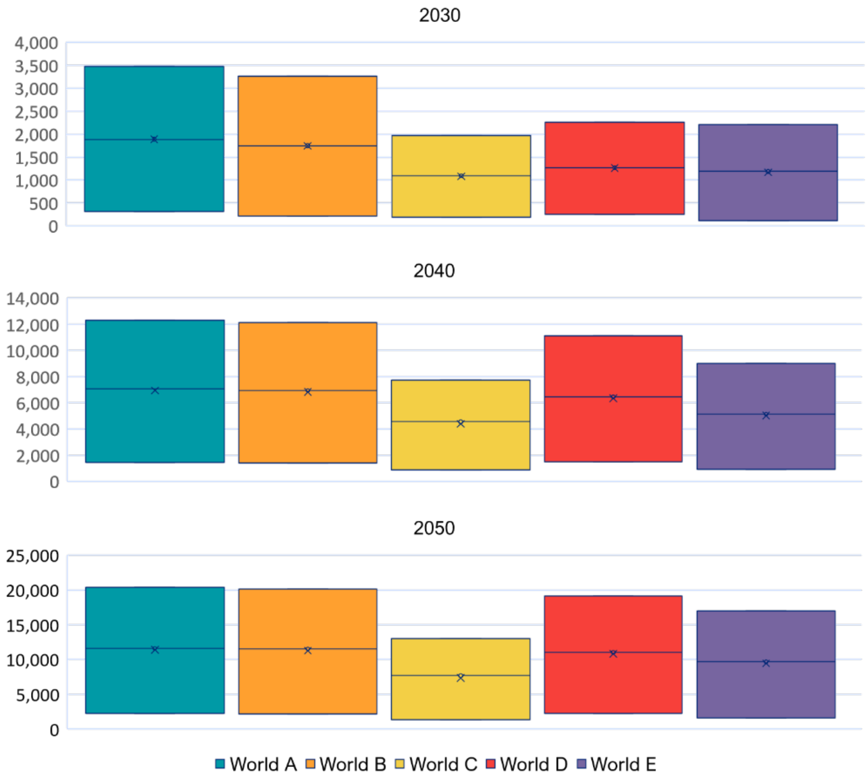
4.1.1 Benefits of improving DER integration

There have been some estimates of the net benefits associated with improved coordination of DER. For example, in GB Baringa Partners undertook an initial high-level cost benefit analysis (CBA) of the costs and benefits of improving DER integration as part of the Energy Network Association's Open Networks project. The Open Networks initiative considered how future industry structures could best deliver services from DER to address requirements at the transmission and distribution level. The benefits considered in the analysis were the reduction of balancing costs and avoided costs for new generation and network investment.

The figure below presents the results of the CBA for different market models (referred to as 'worlds'). The range of estimates for each model reflects the ample margin of uncertainty around the inputs used in the assessment, with the black lines indicating the 'central case' for each model. [81] The range of estimates is very wide. By 2050, net benefits in most models range from £2 billion to £20 billion (in real 2018/19 prices, present value terms), with the timing of gains depending on the specific model adopted.

[81] Baringa (2019), p. 4-7.

Figure 11: Overall net benefits of the 'Future Worlds' in 2030, 2040 and 2050 under the Community Renewables future energy scenario (FES), £m net present value (real 2018/19 prices).



Source: Baringa (2019), p. 7

Baringa undertook a similar CBA of local markets in the context of the Open Energy Networks project in Australia (an initiative of Energy Networks Australia, distinct from the UK Open Networks project). Benefits varied considerably depending on future DER uptake. The analysis concluded that in a high DER penetration scenario, local market models could deliver net benefits in the order of AUD 3 billion. In a lower DER penetration scenario, however, the net benefits were estimated in the region of negative AUD 600-800 million.[82] Using December 2019 exchange rates, the results would roughly translate to a range between negative £300 million and £1.5 billion (without accounting for differences between the Australian and UK contexts).

We note that the results of these CBAs may not be representative of the net benefits of the local market models presented in this report. Firstly, the CBAs were initial exploratory analyses, based on high-level descriptions of local market models. The modelling relied on simplifications and assumptions which may now be outdated, and results for Australia may not be directly transferable to GB. For example, our understanding is that the benefits assessment was mainly focussed on the operation of DER in balancing timeframes and did not specifically consider the impact of changes to wholesale market arrangements.

[82] Energy Networks Australia (2020), p. 34.

Further, the worlds described in the GB reforms have somewhat different architectures and in some cases are less detailed in terms of bid/offer formation and market optimisation and clearing process than the models set out in this report. Broadly speaking:

- World A reflected elements of Model 2, in that the DMO[83] participates in the transmission-level market in a similar way to other transmission-connected parties.
- World B reflected elements of both Models 1 and 3, in that the TMO was able to directly procure services from DER but with an assumption that DSO needs are prioritised.
- World C did not reflect any of the local market models, as it was focussed on facilitating efficient DER integration through access and charging arrangements rather a market-based approach.
- World D was similar to Model 1, with a central system operator co-optimising the distribution and transmission systems.
- World E shared features of Models 1 and 2. Like Model 1, a single entity co-optimises DER procurement (and eventually dispatch) for both transmission and distribution systems. However, rather than optimising the whole system, the role of this entity is limited to DER. Like in Model 2, there is a separate TMO function procuring services both from transmission connected parties and (independent) DSOs to address transmission needs.

The GB Open Networks CBA also highlights the possibility that other sector reforms (see section 1.4) could either achieve some of the benefits captured in these analyses (e.g., by providing better coordination of DER through network tariffs and access arrangements), or alternatively mute the benefits that local markets could potentially deliver. For example, to undertake the CBA, Baringa assumed that the improved network access and charging reforms of World C would also be featured in all the other worlds.[84] Therefore, the net benefits associated with Worlds A, B, D and E all include a substantial element that is not specifically attributable to more efficient market arrangements.

4.1.2 Additional benefits of local markets

As noted in section 2.5, the extension of existing initiatives – without moving to a full-blown local markets approach – can likely achieve some of the benefits described above from better integrating DER into the power system. For example, the Baringa CBA attributed a share of the above benefits to:

- The role of ANM schemes in deferring or avoiding distribution network investment. As described in section 2.5, ANM schemes are already being deployed by DNOs and their use is independent of a decision to introduce an overarching local market model of the type described in this report.

[83] The future worlds used different terminology to describe the local market roles reflect this report, focussing on DSOs and the ESO.
[84] Baringa (2019), p. 9.

- Improved access of DER to transmission level markets. DER have recently gained better access to the balancing market, and Elexon is considering reforms to widen DER participation in the wholesale market.
- We suggest that the specific contribution of local markets, above and beyond broader improvements in DSO capabilities, relates to:
- Enabling the most efficient system-wide market clearing solution, across both transmission and distribution level resources. This may deliver incremental efficiency gains in the utilisation of both transmission and distribution level resources. The materiality of this effect is likely to depend on whether overall system costs would be significantly lower (implying a materially different dispatch) if there is a joint clearing process. This will in turn depend on patterns of supply and demand, and the topologies of the distribution and transmission networks.
- Providing a consistent definition of responsibilities for dispatching resources at the transmission and distribution network levels through an integrated market clearing process itself, avoiding the need for primacy rules.[85] The materiality of this benefit is likely to depend on:
    - How successfully the DNOs and NGESO can develop primacy rules that resolve potential conflicts between DNO flex markets and ANM schemes and the markets operated by NGESO – such that DER participation in the existing transmission level markets is not unduly restricted.
    - The magnitude of the inefficiency should primacy rules not be successfully developed and implemented.
- Potentially, depending on the pricing approach adopted, the provision of sharper locational price signals to distribution-connected resources relative to current arrangements. Sharper price signals may improve incentives for flexible DER to offer services and/or locate in parts of the network where flexibility is most valuable. As discussed in section 3.6.6, this outcome only arises with certain pricing models. This decision is closely linked to consideration of reforms at the transmission network level.

Overall, we have found limited evidence from our review of the literature to support a view on the materiality of the potential incremental benefits arising from the introduction of a local markets model. As we discuss in Section 5, this may point to a more cautious approach to developing and implementing a local market model.

4.1.3 Impacts on the business case for low-carbon technologies

In light of the REMA objective to facilitate decarbonisation of the sector, it is relevant to consider how local markets might impact low-carbon technologies in particular.

Our view is that a local markets approach is inherently technology neutral. This is because there is no special incentive or advantage offered to any particular technology through the market itself. However, there could be some indirect impacts. In particular, a local market

[85] As described in section 2.5, primacy rules determine what happens if directions issued by a DSO and the ESO conflict with each other.

approach could facilitate more effective utilisation of DER. For example, if a lack of visibility of network constraints results in a degree of conservatism to ensure that system limits are not breached, more accurately representing these constraints in the balancing mechanism might allow more DER to participate. To the extent that new DER are low-carbon technologies (e.g., solar PV, wind, storage), this may provide a benefit to their business case.

4.2 Costs

As noted in section 4.1.1, there have been some estimates of the costs and benefits associated with steps to improve DER integration:

- Baringa Partners' CBA for the Energy Network Association's Open Networks project in GB estimated the costs associated with new systems, IT, and resources required, and the cost of paying DER for 'flexibility'. Costs in the central case were estimated to be in the range of £500-800 million by 2050 (2018/19 real, present value terms).[86]
- Baringa's CBA for the Open Energy Networks project in Australia estimated costs in the order of 2.5-3.5 billion Australian dollars (in present value terms at 2019/20 prices) by 2040. Using December 2019 exchange rates, this translates to roughly £1.2-1.7 billion.

We note that these estimates may not be representative of the incremental costs of implementing the local market models presented in this report. For example, we understand that the CBA did not consider costs to change the existing day-ahead and intra-day markets from an exchange based model (that does not represent transmission constraints) to an ahead-market that does reflect network constraints. DNOs may ultimately incur many of these costs (for example, to enhance the technical operability and visibility of distribution networks, particularly at lower voltage levels) to manage their systems more effectively, as they gradually take on DSO-type roles, regardless of whether local markets are implemented. In other words, some of the costs described above are not related to local markets per se, but to the evolution of the energy system more broadly.

At this stage, we do not have sufficient information to identify the additional costs that are specifically attributable to a local market model. However, we expect that these would relate primarily to: the design of the market clearing process (potentially across multiple markets – wholesale, balancing, different ancillary services); system changes to implement the new clearing process (potentially across multiple DMOs and a TMO); and market participant costs of adapting to the new arrangements.

At this stage we do not have strong reasons to conclude that costs would be substantially different across the three models presented in this report, but we note that:

- Model 3 requires less sophisticated coordination between parties, and therefore may be somewhat less costly to implement than Models 1 and 2.

[86] Baringa (2019), p. 8.

- Model 2 may be somewhat less costly than Model 1, as it would allow some flexibility around how DMOs develop the bids/offers submitted to the TMO – for example, DMOs in less constrained networks may adopt less sophisticated, less expansive approaches.

Implementation costs are likely to depend substantially on which existing markets transitioned to a local market approach. For example, as noted in section 3.7 the reflecting network constraints in the day-ahead and intra-day markets would be a very material change from current arrangements, with commensurate costs.

Finally, implementation costs may depend on interlinkages with other REMA reforms.

4.3 Risks

As discussed in the preceding section, a general risk that applies to all the local market models is that the benefits – while potentially significant – are also very uncertain both in size and timing. In turn the costs – which are likely to be significant – could exceed the benefits. Conversely, taking a "slow and steady" approach to the development of local markets – only committing small amounts of resources over time – could result in significant foregone benefits. We explore this point in the discussion of implementation pathways in Section 5.

Some more specific risks are outlined below.

4.3.1 Liquidity and competition

DESNZ has asked us to consider whether the low levels of liquidity that have been seen in DNO flexibility markets could be overcome in a local market model.

In the context of electricity markets, Ofgem defines market liquidity as the ability to buy or sell a product - such as electricity - without causing a major change in its price and without incurring significant transaction costs.[87] Liquid markets are generally characterised by the presence of a large number of buyers and sellers willing to transact at all times. Therefore, a limited number of market participants can pose liquidity issues. Broadly speaking, potential issues include:

- If a product is illiquid, the price at which it is sold may not reflect its real market value.
- If there are few sellers, there may also be concerns related to the competitiveness of the market.
- A limited number of sellers might also mean that the market cannot be relied upon to meet demand for the service in question. This may be particularly problematic in a context where a service is being procured in (or close to) real time.
- More generally, limited participation in could limit the benefits of better integration and coordination of resources that a market is intended to achieve.

[87] Ofgem, https://www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/electricity-wholesale-market-liquidity. Accessed December 2022.

Liquidity has been discussed as an issue in the context of DNO flexibility markets. In this context, limited market participation may be a consequence of the limited geographical scope of the market, revolving around specific local constraints, or the costs for DER of participating in the market exceeding the benefit they can derive from it.

For example, in the context of IntraFlex, a recent trial of a short-term marketplace for the procurement of DNO flexibility, Western Power Distribution (WPD) noted:

"A key objective of the trial was to demonstrate the viability of the platform and market design to create a suitable environment for competition in securing Flexibility contracts. To achieve this, there is a prerequisite that you have sufficient sellers and buyers to make competition a reality. As DNOs are regulated monopolies there will in most cases (in the absence of secondary trading or the ESO purchasing flex in the same order books as the DSO) be a limited number of buyers, but sellers are also restricted by the necessity that their assets are located downstream of a constraint." [88]

A new WPD initiative, 'Generating Additional Markets for Mature Access to Flexibility' (GAMMA Flex), is now considering solutions to the gaps identified in IntraFlex. The absence of a direct link between DNO-level flexibility procurement and ESO procurement of balancing services is one of these gaps. Such a link would be *"expected to help build liquidity in the DNO level flexibility market, as it would encourage [Flexibility Service Provider] participation by enabling them to participate with assets located both inside and outside of WPD's congestion zones and enable revenue stacking"*. [89]

This observation suggests that local markets that coordinate resources at the distribution and transmission level may be less likely to suffer from liquidity issues than standalone DNO flexibility markets that seek to address a specific distribution system constraint, because they are broader in scope. In DNO flexibility markets, the number of sellers is limited to those whose assets impact a specific network constraint. In the local market models considered in this report, the market operator(s) is seeking to procure resources to balance demand and supply across the transmission and distribution network levels. While DER dispatch in the local market would still have to comply with any network constraints at the distribution level, the overall number of participants in the market is likely to be larger, as the need being addressed is potentially much broader (and DER resources may also be competing with transmission connected resources). Further, the likelihood of insufficient offers to meet system requirements is far less likely, as all flexible resources at the transmission and distribution networks are available to ensure that supply and demand balance at the national level.

Any costs and complexities associated with DER participating in local markets can also discourage entry and limit liquidity. Costs might include, for example, administrative requirements and having to fit DER with any monitoring, metering, communication, and control equipment required to enable their participation. Another element of complexity is how closely the DER owner needs to be involved in the operation of their DER unit(s) in order to participate

[88] WPD (2022), IntraFlex – NIA Major Project Closedown Report, May, p. 38.
[89] Smart Grid Consultancy (2022), GAMMA Flex Draft Market Design and Stakeholder Questionnaire, August, p. 5.

in the market, or whether a supplier/aggregator could participate in the market on their behalf. Keeping costs and complexity at a minimum and avoiding overly restrictive requirements should encourage participation, although ultimately this will also depend on the value that DER can deliver via local markets and whether it exceeds their opportunity cost of providing the service.

Other factors that would affect liquidity in local markets have been identified in the literature:

- Another gap identified in GAMMA Flex is that flexibility service providers were not allowed to trade their positions, e.g., in cases where they were operationally unable to deliver flexibility they had sold, or if they choose to trade out of their position for commercial reasons. GAMMA Flex identified secondary trading as a solution to support market liquidity.[90]
- The standardisation of products that DER can offer to the market (i.e., requiring that bids/offers have the same characteristics, for example in terms of reaction times and delivery period) can affect market liquidity. In DNO flexibility markets, a less standardised approach at the expense of liquidity may have the advantage of meeting very specific DNO needs and allowing for specific characteristics of DER flexibility to be better valued. In local markets, standardised products can promote liquidity by facilitating price transparency and competition between DER.[91]
- When considering nodal pricing as an option for locational wholesale pricing, the REMA consultation paper noted that *"dividing the current national market into hundreds of smaller markets raises concerns for liquidity within the bidding zones, though the precise impact on market liquidity is unclear"*.[92] These concerns potentially extend to local markets if nodal pricing were to be applied at the distribution level.
- Finally, the specific local market design adopted may have an impact on liquidity. Under Model 1, DER assets connected to a distribution network would compete directly, not only with other DER on the same distribution network, but also versus transmission connected resources and potentially against DER in adjacent distribution networks, to the extent that network configuration allows that. These elements of competition exist also in Model 2, although competition between resources connected to different networks would more indirect, as it would be mediated by the TMO role of evaluating different DMOs' aggregate positions against one another and transmission connected resources. In Model 3, DER assets do not compete against resources connected to other distribution networks or the transmission network, but only against DER assets within the same distribution network, as the net injection/withdrawal at the transmission connection point is taken by the TMO as a fixed input into market clearing.

These factors would all require careful consideration if a more detailed local market design for GB is contemplated.

[90] Smart Grid Consultancy (2022), p. 4.
[91] Schittekatte, T. and Meeus, L. (2020), *Flexibility markets: Q&A with project pioneers*, Utilities Policy, Volume 63, April.
[92] BEIS (2022), p. 71.

4.3.2 Community and stakeholder acceptance

A key challenge implementing a local market may be community understanding and acceptance of the reforms. As described in section 2.5, a defining feature of the local market is that it is allocating scarce distribution network capacity via a market, on the basis of willingness to pay. This may be inconsistent with notions of “fairness”, particularly for a service which has traditionally been considered as “essential” and has always had a substantial degree of cost sharing between end users.

Alternatively, market participants could be allocated access to the network in a non-market-based way (e.g., everyone gets a fixed proportion of the available capacity). This might be considered a fairer approach, but appears to be inconsistent with the idea of a local market.

Community acceptance may be enhanced if local markets are as open to participation as possible – with regard to the type of consumers (large and small) and type of markets (energy and ancillary). This may drive the most value to the system as a whole, as well as to individual consumers, in addition to reducing perceived biases in the market design.

Nevertheless, local markets are also complicated. The physical generation, consumption and flows of electricity, and prices/transactions that occur, can be counter-intuitive and highly sensitive to time, location, network conditions and the bids / offers of other market participants. Community acceptance might be greater if smaller or less sophisticated participants are not required to have a detailed understanding of what is happening because, for example, their participation in the market can be automated via a third-party service provider. However, in this scenario market outcomes – especially where counter-intuitive – need to be clearly explainable and auditable.

The introduction of local markets – and their specific design – may compliment or disrupt business models that are already emerging, or could be expected to emerge, under the current framework. For example, business models may be emerging in response to the specific products and features of DNO flexibility markets – which might not be replicated in a system-wide implementation of a local markets approach. This in turn is likely to create stakeholder pressure to implement the local markets in a certain way – or not at all – which may cause delays or diminished benefits. This presents trade-offs related to the speed at which a firm policy direction for local markets is developed. We consider this issue further in relation to implementation pathways in section 5.

A thorough study of end-consumer and community expectations with regard to local markets is beyond the scope of this study. Accordingly, the points raised above should be validated and the statements provided in this report could be more robustly tested.

4.3.3 Enforcement of market rules

Local markets may have millions of individual market participants. This gives rise to specific enforcement challenges that do arise to such a degree as at the transmission level.

Understanding of rules and responsibilities by individual consumers is likely to be low, although this burden may be shared by an aggregator acting on behalf of a consumer. Breaches to rules might include clearly nefarious or even illegal behaviour (such as tampering with meters or falsifying data) to less extreme acts such as misleading bidding behaviour. Enforcing rules may be challenging given the vastness of the market.

Participation in the market is likely to be stifled without participants (or aggregators) trusting that the rules are enforced or enforceable.

4.3.4 Customer protections

Given the essential nature of electricity, consumers have a degree of protection above and beyond that of general consumer protection law.[93] A thorough review of consumer protection arrangements is beyond the scope of this study, but we expect that these arrangements may need to be adapted to facilitate local markets (or, possibly, regardless of the introduction of local markets simply based on the ongoing technological changes within the sector). For example, is the same level of consumer protection required when the consumption is for heating or cooking, as compared to charging an electric vehicle, or exporting electricity to the grid? Many may consider that the former activities are essential (warranting a higher degree of protection), while the latter are non-essential (and hence onerous regulations may risk stifling uptake, increasing costs, and hindering innovation).

4.3.5 Data protection and privacy

Relatedly, local markets give rise to data protection and privacy issues - although to an extent these issues may also arise through non-market mechanisms to facilitate more efficient use of distribution-level resources.

End-consumers’ interactions with local markets – whether directly or via an aggregator – is likely to produce large amounts of information relating to the consumer’s behaviours (e.g., consumption patterns – when they are in the house, when they expect to return home, what type of car they drive) and preferences. This in turn gives rise to the possibility of this data being made available (legally or otherwise) or used for purposes considered unacceptable to the end-consumer itself or society more generally.

Substantial analysis on data protection / privacy issues relating to local markets is beyond the scope of this study.

[93] For example, as contained in the Standard conditions of electricity supply licence: https://epr.ofgem.gov.uk//Content/Documents/Electricity%20Supply%20Standard%20Licence%20Conditions%20Consolidated%20-%20Current%20Version.pdf

5. Implementation pathways

In this section, we outline considerations related to the possible implementation of a local market model in GB. These considerations include the current and planned future capabilities of the DNOs and the ESO, and compatibility with other REMA reforms. Finally, we conclude with some suggested next steps that could help to further advance policy thinking in this area.

5.1 Enablers of local markets

As highlighted in section 3.6, the local market models described in this report rely on better information on constraints and resources at the distribution network level than exists today. More specifically, advances would be needed in relation to system monitoring, the representation of distribution network constraints in a market clearing algorithm, and communication with DER that participate in the market.

In GB, the DNOs and ESO have already been working towards developing these capabilities – through the Open Networks initiative and the DSO Roadmap developed by the ENA, as well as through the business plans individual networks have put forward through the RIIO-2 price control. Finally, Ofgem is currently in the process of reviewing the institutional and governance arrangements that apply at the sub-national level in GB, which will also impact the practical implementation of a local market approach. In the following sections, we comment on these processes and their implications for a transition to a local market approach.

5.1.1 ENA Open Networks – DSO transition plans

The ENA has compiled a DSO Roadmap[94] to provide visibility into DSO functionalities already implemented to date and potential timeframes for future implementation. The roadmap includes eight functions, further subdivided into activities and steps.

The table below summarises our understanding of progress with respect to some of the activities that are most relevant to the implementation of local markets. This is not a comprehensive summary of all the activities planned or underway in the DSO Roadmap, which has a broad scope encompassing functions such as investment planning, connections and connection rights, system defence and restoration, and charging.

It is important to note that some of the reported dates are based on the expected completion of specific projects that are on foot, and that not all DNOs have specified completion dates for each step. We understand that this reflects different conditions: these steps will naturally be a higher priority for DNOs that manage constrained networks. Further, DNOs may apply slightly different definitions for what constitutes completion. Accordingly, these dates are best viewed

[94] ENA, https://public.tableau.com/app/profile/open.networks/viz/ENADSORoadmapQ32021/Roadmap. Accessed December 2022.

as indications of maturity in certain areas, rather than a definitive account of specific capabilities.

Table 15: Progress in the implementation of selected DSO roadmap activities

Function	Activity	Progress (steps recently completed or underway)
System Coordination	Coordination with GB system operator	Developing processes and IT infrastructure to facilitate real-time data exchange and forecasting (most DNOs by 2023). Advanced wind and solar energy forecasting by the ESO (2023). Developing whole system approach to reactive power services (all DNOs by 2023). Applying primacy rules for addressing T-D flexibility service conflicts (within ED2). Some DNOs already have a communications link to the ESO control centre. Other have just initiated this and expect to complete it by 2028.
Network operation	Operate within thermal ratings	Improve operational DER visibility and monitoring (some DNOs by 2023, others have just initiated this process).[95] Develop visibility of LV data (all DNOs by 2025).
	Operate within voltage limits	Develop an approach to LV system monitoring (all DNOs by 2025). Development of reactive power voltage control services (some DNOs by 2023, others have just initiated or are not currently planning this activity).
	Operate to maintain dynamic stability	Develop consistent approach to use dynamic stability mechanisms (to manage power quality) using ancillary services (2028 for UKPN, other DNOs have just initiated or are not currently planning this activity).

95 In the DSO Roadmap, the term “initiated” indicates that an organisation has planned the implementation of a certain step. The organisation has not necessarily defined implementation dates at this stage.

Function	Activity	Progress (steps recently completed or underway)
	Operate within fault level limits	Prevention/management of fault level issues through enhanced monitoring (some DNOs by 2023, others have just initiated or are not currently planning this activity).
	Meet power quality criteria	Rolling out power quality meters (all DNOs have at least initiated this activity, ENWL expects to complete by 2028).
	Operate network taking account of ongoing asset condition	Upgrade modelling at all voltage levels to support design and operation – e.g., prediction of load, real-time power flow management (all DNOs by 2025). Installing monitoring equipment linked via SCADA to network control systems (all DNOs by 2028).
	Optimised use of assets and dispatch services	Developing DNO ability to incorporate third party data into network planning and operation (e.g., individual asset metering, settlement data, load/generation forecasts, and data from other markets for coordination) – This capability was explored recently through projects such as EFFS, Transition, and Fusion.
Services and market facilitation	Assess value	Common baseline methodologies for flexibility services (most DNOs by 2023).
	Facilitate the operation of DER Management Systems and Local Energy Markets	Development of a Neutral Market Facilitator platform (2023) – as part of project TRANSITION, SSEN and Opus One are developing an IT platform to automate the procurement of flexibility services.[96] Implementation of embedded capacity register (all DNOs by 2022).
	Service conflict mitigation/resolution	Roll-out architecture of control/comms systems between transmission and distribution to manage conflict of services (most DNOs by 2026).

[96] SSEN: https://ssen-transition.com/our-project/what-is-a-neutral-market-facilitator-nmf/. Accessed December 2022.

Function	Activity	Progress (steps recently completed or underway)
	T-D coordination for whole system outcomes	Standardisation of data formats, and communication exchange and protocols for flexibility services (ENA by 2022). Develop whole system approaches to reactive power (most DNOs by 2023). DNOs to adhere to good practice dispatch process (2023). DNOs to publish their decision criteria for near real-time dispatch as advised by dispatch guiding principles (most DNOs by 2023).
	Smartgrid network flexibility	Integrate enhanced DSO functionality within control rooms to manage operations utilising ANM, flexible services and flexible connections (all DNOs by 2023).
	Service selection	Alignment of ESO/DNO timelines for procurement (completed in 2021). Identify good practice in payment and penalties calculation (ENA by 2022). Transparent decision-making when deciding how services are procured from different solutions in order to meet network needs (all DNOs by 2023). Clear approach to the dispatch of flexibility services (all DNOs by 2023). Implementation of systems to manage allocation, dispatch, and settlement of procured flexibility (all DNOs by 2023). Implement pre-qualification process and requirements across all DNOs (action completed by 2023 for most DNOs). Align pre-qualification requirements across T&D (ENA to develop by 2023).

Source: CEPA analysis of ENA's DSO Roadmap.

5.1.2 Funding of DSO capabilities in RIIO-ED2

“Smart optimisation” is one of the key themes in Ofgem’s RIIO-2 electricity distribution (ED2) Final Determinations. This term refers to the DSO activities that require use of smart technologies to minimise cost, provide flexibility to the system, help to balance supply and demand, and actively manage constraints on the network. Ofgem also sees increased data, digital capabilities, and greater network visibility at all voltage levels as a requirement of smart optimisation. DSO activities identified by Ofgem include network planning, LV monitoring, development of open data platforms, and modelling.[97]

While the concept of smart optimisation is not exclusively linked to local markets, the ED2 final determinations create obligations and incentives for DNOs to provide DSO outputs, meaning that, as part of the ED2 price control, DNOs can be funded for building new capabilities, which may also assist in the development of local markets.[98] These initiatives are summarised below.

Ex ante allowances and incentives for DSO functions

To provide appropriate ex ante funding for DSO functions, Ofgem accepted the majority of the DNO's DSO strategy proposals without amendment (following an assessment that the strategies met the minimum requirements under Ofgem’s Business Plan Incentive). While stakeholder consultations highlighted some concern that a lack of standardisation may lead to uncoordinated DSO activities and operational inefficiencies, Ofgem sees value in giving DNOs the space to tailor their approach to reflect the DSO transition issues prevalent in their region.[99]

Ofgem is also implementing a new DSO financial incentive to drive DNOs to develop and use their network, considering flexible alternatives to network reinforcement more efficiently. The incentive is based on an ex-post review of DNOs' delivery of their DSO activities against three evaluation criteria.[100]

The evaluation criteria of the DSO incentive should encourage the rollout of network visibility. Ofgem notes that there has been significant innovation investment in network monitoring over ED1, and these technologies are now mature enough to be deployed at scale. It is expected that all DNOs will achieve full network visibility by the end of ED2 (2028) using a combination of technologies including direct measurement, modelling and smart meter data. In their business plans, DNOs have prioritised the physical installation of monitoring to highly utilised network areas and areas with the highest potential flexibility needs.[101]

[97] Ofgem (2022a), RIIO-ED2 Final Determinations Overview document, November, p. 16.
[98] Ofgem noted the need to future proof these investments against the different potential future models for the DSO . For example, new IT capabilities should be amenable to be transferred to a different entity, if the governance of the distribution sector changes.[98] Any changes to costs, outputs and incentives associated with any future decision on further separation of DSO functions from DNOs will be dealt with through a price control re-opener. Ofgem (2022b), RIIO-ED2 Final Determinations Core Methodology document, November, p. 79 and p. 89.
[99] Ofgem (2022b), p. 79.
[100] The details are set out in Ofgem’s (2022c) Distribution System Operation Incentive Governance Document. A final determination on this document, following recent consultation, is still pending at the time of this report.
[101] Ofgem (2022a), p. 56-57.

Digitalisation Licence Obligation and Re-opener

Licence Obligations (LOs) are a type of output in the RIIO-ED2 framework, which set minimum standards that network companies must achieve. This LO imposes a requirement for DNOs to consult stakeholders and publish Digitalisation Strategy and Action Plans, and to comply with Data Best Practice. This should promote increased consistency between DNOs in data sharing and utilisation.

This Digitalisation Re-opener allows DNOs to apply for additional funding where a change in their roles and responsibilities requires them to establish new or improved digital services.

Smart Optimisation Output (SOO) LO

This will require the DNOs to develop a two-part strategy:

- A Collaboration Plan describing how the DNO will collaborate with stakeholders to share data and support the development of local and regional net zero strategies.
- System Visualisation Interface – This is a section of the DNO's website that provides access to a package of digital network tools. By 2024, these tools should provide detailed asset and spatial information about the DNO's network including the type, capacity and condition of assets as well as details of any specific system constraints.[102]

In addition to the initiatives set out above, Ofgem has set out an expectation that DNOs would be using flexibility in the first instance before considering traditional network investment. To enable this, Ofgem has designed uncertainty mechanisms around load-related expenditure (LRE) to enable DNOs to be responsive to changing demand during the price control, while protecting consumers from the risks of overinvesting ahead of demand.[103]

5.1.3 ESO initiatives

In addition to the activities of the DNOs, NGESO also has existing plans to improve the integration of DER in its markets. These include:

- Proposals to improve its direct operational visibility of DER (beyond collaboration with the DNOs). This includes consideration of metering standards for DER participating in the balancing mechanism and ancillary services markets.[104]
- Options to enable DER aggregators to provide a wider range of ancillary services.[105] This includes requiring aggregators to provide information on the location of aggregated DER, which the NGESO will then map to grid supply points in order to better assess the impact of activating these resources on transmission network constraints.
- Ongoing collaboration with DNOs through the Open Networks project (for example, the development of primary rules).[106]

[102] Ofgem (2022a), p. 61.
[103] Ofgem (2022a), p. 60.
[104] NGESO (2022), *Operational visibility of DER*, May.
[105] NGESO (2022), *Reintroduction of aggregation at GSP Group for DC*, January.
[106] ENA (2022), *Primacy Draft Rules Increment 1 – Open Networks*, April.

- Design and implementation of bespoke solutions (with DNOs) to manage the impact of distribution network constraints in specific locations via Regional Development Programmes.[107]

As with the DNO plans, these steps represent improvements in DER integration which go some way (although not all the way) to realising the theoretical benefits of a local markets approach.

5.1.4 Additional steps required to implement a local market

As described in section 3.1, implementing a local market approach requires multiple design questions to be resolved and additional investments in network operation capabilities. The existing plans of DNOs and the ESOs will go someway towards addressing these implementation questions. However, as the DNO and ESO plans are not targeted an implementing any particular local market model, some additional actions would be needed in order to adopt any one of the three approaches described in this report.

The table below provides an overview of how we understand current plans relate to the design issues and/or technical enablers need to introduce a local markets model. The table categorises each element as either: green (G) – existing plans appear highly relevant for a local markets approach, although these might need to be adapted or extended to implement any particular model; amber (A) – there is some relevance of existing plans to a local markets approach, albeit indirect; red (R) – current plans do not address the design element. This provides a broad indication of what areas might need additional attention if a local market model was to be adopted. It is important to note that this is based on a high-level assessment – a more detailed review of both DNO/ESO plans and a more detailed local market model design would be required to better understand the level of additional effort needed.

Table 16: Additional implementation requirements

Element	RAG	High-level observations
System monitoring	G	Investments in system monitoring are being pursued. The extent of monitoring requirements under a GB-wide local markets approach could be different to current plans.
Constraint development	A	Smart optimisation plans include improvements in system modelling, including distribution network constraints. However, further work may be needed to translate this to (for example) a real time market clearing algorithm.
Forecasting	G	Current plans include improved forecasting of distribution connected resources. The extent / nature of forecasting

[107] NGESO (2022), *Regional Development Programme update 2022*, March.

Element	RAG	High-level observations
		requirements and where responsibility for forecasting sits, would depend on the specific local market model.
Participation requirements for DER	A	Ongoing refinement of DNO flexibility markets and ESO plans to integrate DER into the balancing / ancillary services markets (e.g., metering) may provide useful lessons, although these would need to be adapted to the particular local market approach.
Bids and offers	R	Bid/offer formats and requirements would need to be tailored to a particular local market approach.
Market clearing / optimisation	R	The market clearing algorithm(s) would need to be tailored to a particular local market approach.
Price formation	R	The question of appropriate pricing arrangements under a local market approach is (understandably) not addressed by current DNO/ESO plans. This question is somewhat independent of the local market model adopted, and may be impacted by other REMA decisions (e.g., in relation to nodal pricing).
Dispatch	R	Arrangements for the market operator to issue instructions to participants whose bids/offers have cleared would need to be tailored to a particular local market model.
Settlement	A	Arrangements for the settlement of market participants could potentially operate in a similar way to today. This would need to be reviewed in light of the particular model adopted.

5.2 Interactions with other REMA reforms

This section considers the potential for the local market models to co-exist with a green power pool and nodal/zonal pricing.

5.2.1 Green power pool

Our understanding of the model

The REMA consultation is considering ‘splitting the market’, i.e. some form of separation between the wholesale market for variable and firm power. According to the consultation, benefits of splitting the market could include:

- separating renewables from the rest of the market in order to pass on the lower costs (and higher variability) of renewables to consumers; and
- to some extent, addressing the ‘price cannibalisation’ problem, whereby fluctuations between lower price periods of high renewable output and higher price periods of low output may hinder investment in renewable generation.[108]

The consultation document points to the ‘two markets’ model[109] as the most detailed proposal of this kind, although it notes that many design questions remain open. Prices in the market for variable, ‘as available’, energy resources would be set on the basis of the long-run marginal cost of renewables (i.e. factoring in all the costs of producing that unit of energy, including building a new plant); prices in the market for firm, ‘on demand’, generation would continue to be set by short-run marginal cost (i.e. only factoring in the cost of producing an extra unit of energy, mostly made up of fuel costs).[110] Most consumers would participate in both markets but those who are able to flex their demand more could purchase a higher proportion of their electricity from the ‘as available’ market, while consumers in the ‘on demand’ market would pay a premium for the firmness of supply. In very broad terms, balancing supply and demand would take place as at present.

An alternative design option set out in the consultation document is the green power pool,[111] i.e., a centrally co-ordinated Power Purchase Agreement market for renewable power, which would operate alongside the existing wholesale market:

- Renewable generators would contract with the System Operator to sell their power into the pool at their long-run marginal cost. Participation in the pool would be on a voluntary basis.
- Consumers (on Grubb and Drummond’s conception, mostly industrial and commercial consumers) would sign standard contracts to purchase electricity from the pool, which would be cheaper than the wholesale market but with greater quantity variability. Consumers could choose how much variability they would be willing to accept in exchange for what degree of price reduction.

[108] BEIS (2022), 66-68.
[109] Keay and Robinson (2017).
[110] The consultation document explains that, if this were successful, prices in both markets would be more stable and predictable, as both would tend to reflect the average long-run cost of the generators participating in them (because fuel costs make up a high proportion of the total cost of non-renewable generators).
[111] Grubb and Drummond (2018).

- The System Operator would be responsible for balancing the pool. Any imbalances would be covered through purchases from the wholesale market, the cost of which would be spread over all consumers in the pool.

The consultation document indicates that the green power pool may be a more incremental option than the two-market design, although it is yet to be determined to what extent this approach would capture the benefits of a fully split market, whilst mitigating its complexity.[112]

Compatibility with the local market models

Our understanding is that the two-market model is intended to apply at the wholesale market level – that is, there would be separate exchanges for contracts related to low-carbon and other resources. However, it is not intended to apply to the balancing mechanism.

Therefore, there does not appear to be any conceptual difficulty in combining a split market at the wholesale level with a local market approach in the balancing mechanism. DER could participate in the 'as available' or 'on demand' wholesale markets depending on whether their supply or demand are firm, and pay or be paid accordingly. Real time balancing would then occur in conceptually the same way as described in the local market models above, with the balancing mechanism process taking account of both transmission and distribution level constraints.

However, there would appear to be a conflict between the two concepts if applied together at the wholesale market level. As described in section 3.7, applying a 'local markets approach' to the wholesale market would involve the market being cleared with transmission and distribution constraints being taken into account (i.e., a security constrained economic dispatch). This type of approach inherently requires a whole of system optimisation – which would not appear to be compatible with a split market approach.

Similar comments apply in relation to the green power pool model. DER could enter into PPAs (as either a buyer or a seller), competing on an even footing with transmission level resources (at least under Models 1 and 2 above). As with any other contractual position struck in the wholesale market, imbalance positions versus the PPA contracts would then be addressed in the balancing market, taking into account local constraints. However, combining a green power pool and local market approach in the wholesale market would not appear to be compatible.

5.2.2 Locational wholesale pricing

Our understanding of the model

The REMA consultation is considering moving to locational (either zonal or nodal) wholesale pricing. Under nodal pricing, the physical constraints of the network – capacity and losses – are reflected in the market clearing process, with the associated costs fed through to the wholesale price in each location in the transmission network, also known as a "node", so that the nodal price represents the locational value of energy.

[112] BEIS (2022), pp. 66-68.

Under zonal pricing, the network is split into zones, with boundaries drawn to reflect where major transmission network constraints occur. Each zone has a single price which (like the current single national price) assumes no network constraints within the zone. Where the price for energy differs between two zones, a supplier will pay the difference between the price in the zone it was generated and the price in the zone where the energy is supplied, with the cost difference being the cost of network congestion between the two zones.

Zonal pricing offers a simplified representation of network congestion relative to locational marginal pricing, and may be less complex to implement, but would provide less granular locational signals, which may blunt incentives.

Compatibility with the local market models

The fundamental characteristic of a local, distribution level market is that it takes account of distribution level constraints in the market clearing process – that is, the process of ensuring that the quantity of supply is equal to the quantity of demand at each location on the distribution network.

As noted in section 3.6.6, variety of different pricing arrangements could then apply for the wholesale and balancing markets. We expect that each of the approaches described are compatible with a local market, in the same way that the least granular pricing arrangement currently applies in the wholesale market at the transmission level, and yet functions with a balancing clearing process which – by necessity – takes account of transmission constraints.

Nevertheless, more granular approaches are likely to provide more efficient signals for investment and operational use of the network by generators, storage and load. However, we recognise that the trade-offs associated more granular price signals are being actively debated in GB (for example, how potential impacts on contract market liquidity, the ability for market participants to hedge basis risk, and the accuracy of price signals all combine to influence investment decisions). Recognising that this is a broader debate, we have not commented extensively on this issue for the purpose of this report.

5.3 Summary and recommended next steps

The preceding discussion suggests several considerations that arise from the planned development of DSO capabilities:

- The DSO Roadmap, and RIIO-ED2 plans to develop DSO capabilities, suggest that by the late 2020s the DNOs will have made substantial improvements in terms of visibility of the distribution network. This is an important step towards the implementation of a local markets approach. At the same time, the planned developments are not targeted at developing an overarching local market model for GB (whether generally, or any one particular model). This suggests that implementing a particular market model would likely require additional planning and investment to both identify and then fully develop the required capabilities. For example, any one of the local market models included in this report would require a new clearing algorithm (or algorithms, under Models 2 and 3 with separate TMO/DMOs) to be developed for the balancing mechanism. As described in section 5.1.4, this is not currently being developed by NGESO or the DNOs (although their planned activities may produce information that could inform the design).

- Related to this, a precise definition of the necessary capabilities relies on having a more detailed local market model in mind. For example, while general observations on relevant capabilities can be made, the full implementation requirements would not be known until key design elements – such as the market clearing algorithm, the form and content of bids/offers, and the timing of the steps in the clearing process – are more fully fleshed out. As noted throughout this report, limited design detail is readily available in the literature. The novelty of the concept suggests that the design process might be quite lengthy and would likely need to confront some thorny issues.
- Further, it may be the case the detailed design process might benefit from the experience gained in the development of planned DSO capabilities or the information revealed through improved market visibility.
- Finally, the most appropriate local market design for GB will also depend on interactions with other market reforms – for example, decisions in relation to the introduction of transmission LMPs and split markets. Similarly, Ofgem's imminent decisions in relation to governance and institutional arrangements may also point to a particular approach being more suitable. This decision may also in itself provide a framework through which a local market design and/or implementation decision could be progressed.

Implementation considerations are also impacted by the benefits case for introducing local markets. As noted in the preceding sections of this report:

- Local markets can support more efficient use of transmission and distribution system networks and resources, which would contribute to lower system costs. However, the magnitude of the inefficiency is at present uncertain.
- Local markets can support improved locational price signals, although this depends on their implementation.
- The potential benefits of local markets are also likely to be affected by other market reforms – for example, widening the participation of DER in wholesale markets.
- Finally, REMA is aimed at putting in place market arrangements that can support decarbonisation of the energy sector by 2035. While it is difficult to be precise about potential implementation timeframes for a local market approach, the points raised above suggest that no earlier than 2030 may be a realistic expectation.[113] As a result, while implementation might be completed before 2035, a local market model might not be expected to contribute materially to meeting the REMA decarbonisation objective by this date.

Overall, we consider that a local markets approach is consistent with the REMA consultation paper's focus on improved locational signals and distribution network visibility. However, there

[113] For comparison, the Baringa CBA for the Open Networks Future Worlds assumed that the worlds would be fully implemented between 2028 and 2036, depending on the approach taken.

are questions around the materiality of the potential benefits, the scale of the investment needed, and the timeframes in which the benefits might be achieved.

This may point to a relatively incremental approach to further policy development in relation to local markets. In this context, we suggest that useful next steps may be to:

- Consider developing the design of a local market model in greater technical detail. For example, this might involve further scoping of the market clearing algorithm under the different options identified, which may help to inform a judgement on feasibility and also the scale of implementation challenges.
- Explore whether the benefits associated with particular local market models could be more precisely identified. Independent quantification of benefits was outside the scope of this report. However, it may be possible to find indicators that could inform a view on the scale of the market inefficiency that might persist if a local markets approach is not adopted. Possible avenues of exploration include the extent of current and future conflicts between DSO and ESO instructions to DER.
- Assess whether other REMA market design directions, and Ofgem's conclusions in relation to governance, could potentially narrow the scope of local market models for consideration. As outlined in the body of this report, local markets are a broadly defined concept and the range of possible permutations is wide. If the scope can reasonably be narrowed to be compatible with other decisions (that would likely be introduced sooner), this may provide a clearer view on possible implementation steps and timeframes.
- Maintain a watching brief on the progress against DSO transition plans in GB as well as innovation trials that are taking place in other jurisdictions.

Appendix A Approach to literature review

Our approach to the academic literature is summarised below:

- We initially reviewed papers published within the last 3 years (2019 – 2022). Papers were not limited by geography.
- We used Google Scholar to search for papers that included key terms relevant to local markets (see the table below).
- We reviewed the abstracts of the identified papers to narrow the selection down to a shortlist of c.50 papers for further review.
- Our review of the shortlist identified some older publications that were relevant. These were also included in the shortlist for review.

Table 17: Search terms

Search terms
“distributed locational marginal price” AND “electricity” OR “energy”
“distribution locational marginal price” AND “electricity” OR “energy”
“distribution market operator” AND “electricity” OR “energy”
“local electricity market” AND “transmission”
“local energy market” AND “transmission”

“Transmission” was included as a search term alongside “local electricity market” and “local energy market” in order to identify papers that considered system-wide models, including the interaction between the transmission and distribution network levels.

To source relevant literature prepared by industry bodies / government agencies, we identified the most recent investigations of local market models that have been undertaken (or are currently being undertaken) across several jurisdictions. We prioritised:

- GB – to ensure existing thinking was captured. Our review identified the ENA’s Open Networks project as the most relevant recent review.
- the EU – given future interactions between GB and EU electricity markets. We identified the ongoing CoordiNet project as the most recent, and in depth, examination of local market issues.

- Australia – where these issues have been considered in detail, given exceptionally high levels of DER penetration. Our review focussed on the Open Energy Networks collaboration between the Australian Energy Market Operator and Energy Networks Australia.

While we did not directly include the US in this review, through the academic literature we identified and reviewed materials from the Future Electric Utility Regulation (FEUR) series produced by Berkeley Lab.[114] Their report on 'Distribution Systems in a High Distributed Energy Resources Future' was included in our review.

While reviewing the grey literature, we also identified numerous innovation trials that are developing and testing elements of local market models. Information from selected trials – including the Cornwall Local Energy Market trial in GB – was incorporated. However, our analysis of this material was limited, given the very extensive and technical nature of the publications and the time available for this review. Trials may be a useful source of information should DESNZ wish to further pursue the development of a local markets model.

[114] Lawrence Berkeley National Laboratory is a US Department of Energy Office of Science national laboratory, managed by the University of California.

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